2.0 Trends affecting electric service costs

2.1 Overview

This section of the report describes trends affecting electric service costs for Washington consumers. To put those trends in perspective, it begins with a characterization of the existing costs paid by consumers, broken down into the three primary components of electric service: generation, transmission, and distribution. While all three of these components represent significant costs, generation is both the largest and the most susceptible to changes associated with recent trends toward competition.

After briefly describing these existing cost characteristics, this section will examine trends affecting electric service costs in six broad categories:

1) Wholesale market developments
2) Retail market developments
3) Load/resource balance (the relationship over time between demand and supply)
4) Environment
5) Technology
6) Fuel cost

In the preceding section describing variations in prices, some trends may be discerned with respect to the distribution of costs among customer classes. However, this section will primarily address trends that affect total electric service costs. Trends and strategies that concern distributional issues are covered more fully in Section 4 of this report.

2.2 Existing cost characteristics

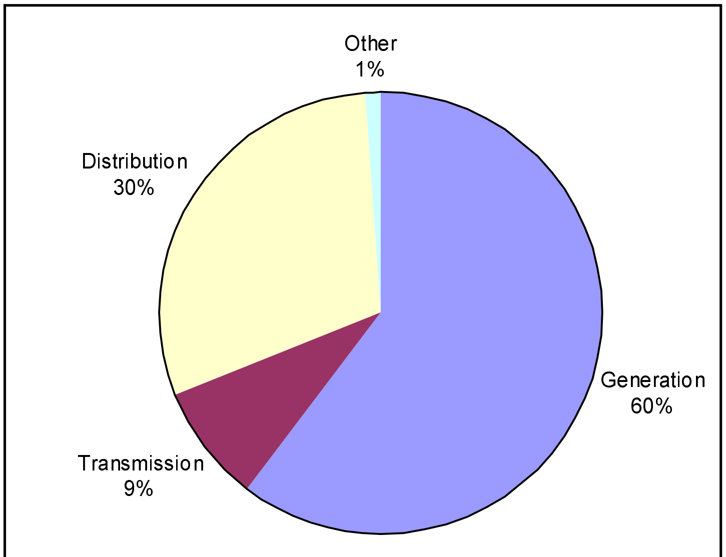
The following sections characterize Washington's costs of electric power service, broken down by generation, transmission, and distribution. The pie chart below shows the share of total (internal) costs in each category for the utilities reporting under HB 2831.

Generation

The most significant factor distinguishing the existing cost profile of Washington's electric power system is the predominance of relatively low-priced electrical generation. The average price of Washington's electrical generation* is 2.3 cents per kWh compared to a national average of [XX-waiting for EIA data].

* With the development of increasingly active wholesale and retail markets in the Western US and Canada (the Western Interconnection), it is becoming increasingly difficult to specify any particular set of generation resources that can accurately be called "Washington's". However, since low-priced generation is the primary reason for Washington's low rates, an examination of the characteristics of the resources used to serve Washington consumers is still instructive.

Figure 2.1 Internal Costs by Category for HB 2831 Reporting



Source: HB 2831 Unbundled Cost Reports

Unique features that may account for this difference include:

2.2.1.1 Preferential access to federal generation resources at cost-based rates.

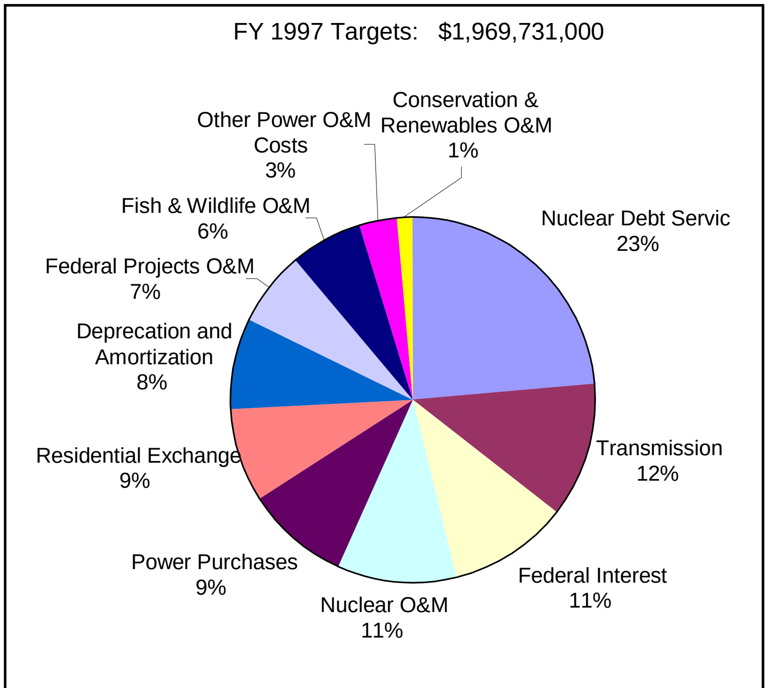
Approximately half of Washington electric power requirements are served by federal resources from the Federal Columbia River Power System. The price of power from the FCRPS is approximately 2.3¢ per kWh, compared to a national average of [XX] per kWh. The FCRPS consists primarily of hydropower. However, while nuclear generation accounts for only 7% of FCRPS output, it represents about one third of the cost of power from the system (including debt service on terminated plants). The costs of the FCRPS also include costs associated with accomplishment of BPA's statutory missions, including the costs of serving low-density rural systems; the costs of mitigating damage to fish and wildlife; and the cost of investments in energy efficiency and new renewable resources. Figure 2.2 shows the breakdown of Bonneville's costs among various categories.

Figure 2.2 Washington electrical generation compared to other states and/or national average

Chart Washington generation costs vs. other regions – waiting for EIA data

The price of power from the FCRPS has remained relatively low and stable since the system was put into service, with the exception of a dramatic increase in wholesale prices from 1979 to 1983, when the costs of the WPPSS nuclear plants were absorbed in BPA rates. Today's rates are very close to their 1983 level in nominal terms. In real terms, they have declined since 1983.

Figure 2.3 Bonneville Power Business Line Expenses

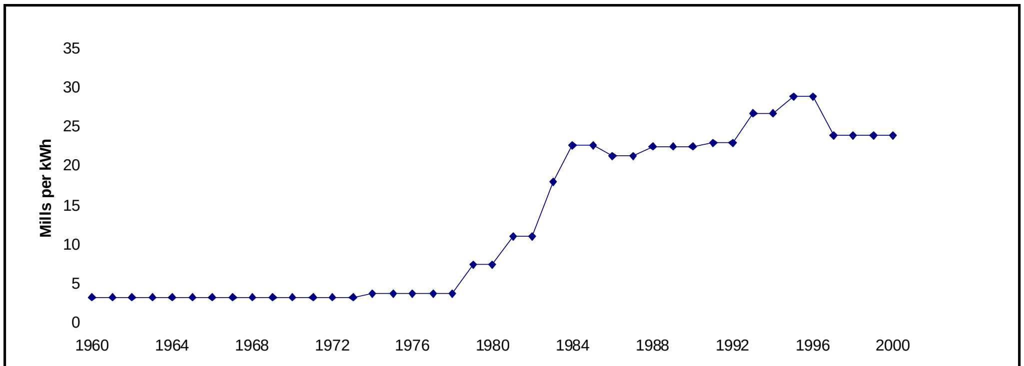


Source: Bonneville Cost Review

The difference between the cost of power from the Federal system and its value historically has been quite large. That difference accrues to the beneficiaries of cost-based rates from BPA: Northwest public agencies, the residential and small farm customers of investor-owned utilities, and BPA's Direct Service Industrial customers, primarily aluminum smelters. It is difficult to evaluate how large this difference is likely to be in the future. However, according to the Northwest Power Planning Council, it appears to be substantial under a fairly wide range of assumptions about future market conditions and federal system costs (See Figure 2.4). Intense interest in securing allocations of FCRPS power in the current BPA subscription process confirms the growing perception that the value of this power will continue to exceed its cost.

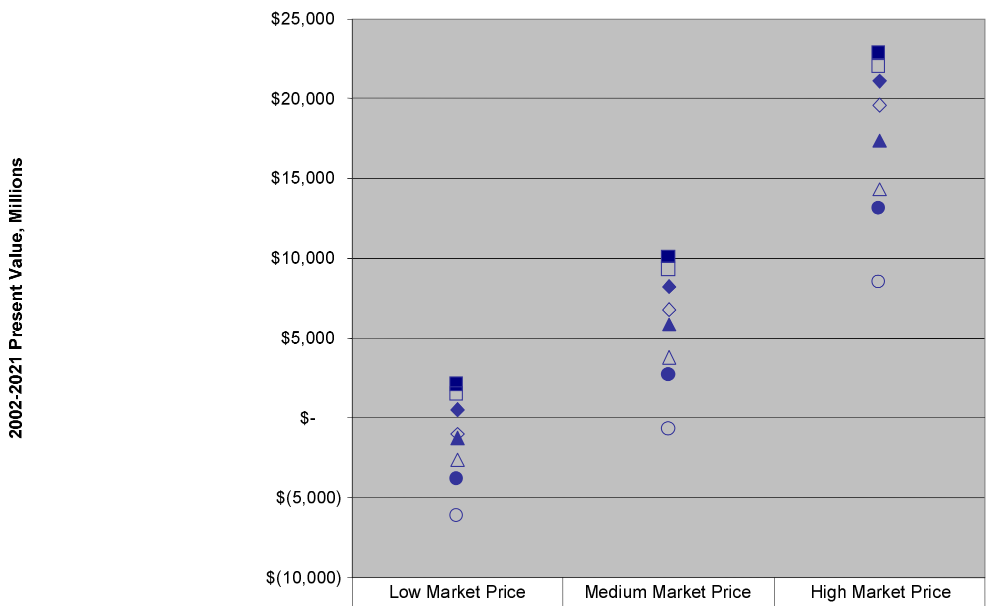
Figure 2.5 shows the long-term value of the FCRPS under a variety of scenarios for salmon recovery strategies and market conditions. As indicated in the chart, market price is probably the most significant uncertainty in assessing the value of the federal system over the next 25 years. In the low market scenario, the real price of power climbs from 17 mills/kWh in 1998 to approximately 19 mills in 2007, before beginning a gradual decline to 13 mills by 2021. In this scenario, the net present value of the

Figure 2.4 Bonneville Rates, 1960-2000



Source: Bonneville Power Administration

Figure 2.5 Projected Value of Federal System Under Various Scenarios



	Low Market Price	Medium Market Price	High Market Price
■ Reduced Flow Augmentation	$2,045	$9,995	$22,770
□ 95 BiOp	$1,450	$9,201	$21,944
◆ Transportation Plus	$474	$8,253	$21,061
◇ Transportation Plus, Clean Water Act (CWA)	$(994)	$6,784	$19,593
▲ Lower Snake Drawdown	$(1,244)	$5,834	$17,346
△ Lower Snake and John Day Drawdown (Five Dams)	$(2,663)	$3,832	$14,317
● Five Dam Drawdown, CWA	$(3,896)	$2,599	$13,084
○ Five Dam Drawdown, Flow Augmentation, CWA	$(6,219)	$(763)	$8,470

salmon recovery scenarios. The medium market scenario foresees real prices of 23-25 mills from 2000-2021. Only the most expensive fish cost option, involving a five dam drawdown, flow augmentation, and modification of remaining dams for Clean Water Act compliance, results in a net present value for the system of less than $2.5 billion.

2.2.1.2 The prevalence of hydropower in Washington's resource mix, and particularly the prevalence of large hydro projects

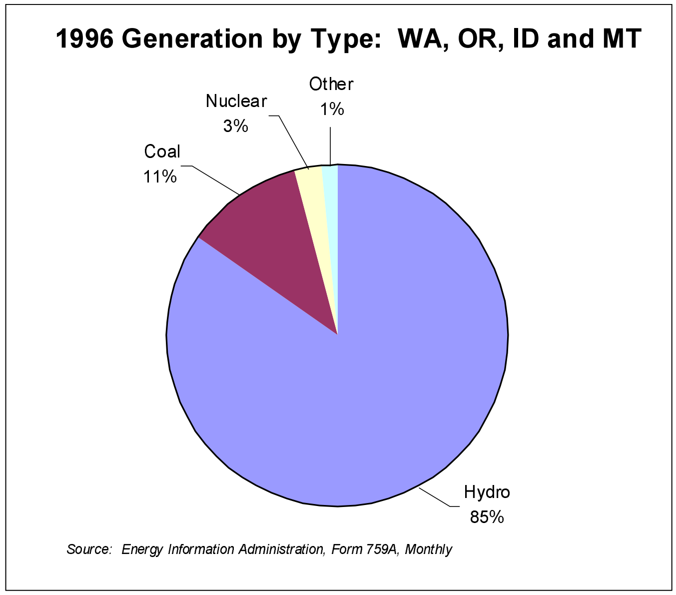
Because Washington is part of an integrated regional grid, it is not possible to determine exactly how much of the electricity generated for Washington consumers is hydropower. However, we can get a good indication by looking at the power generated in a slightly larger region. In the four Northwest states (Washington, Oregon, Idaho and Montana), hydropower accounted for 85% of electric generation in 1996. Of this amount, projects larger than 300 MWa accounted for 77%. For a variety of reasons including scale, these larger projects tend to produce lower-priced power.

2.2.1.3 The age of Washington's resource mix

Very little electric generating capacity has been added in the region in the last decade.

As a general rule, older projects tended to have lower construction costs, were financed at lower interest rates, have already amortized much or all of their capital costs, and may have internalized fewer environmental costs.

Figure 2.6



2.2.1.4 The prevalence of publicly-owned generation

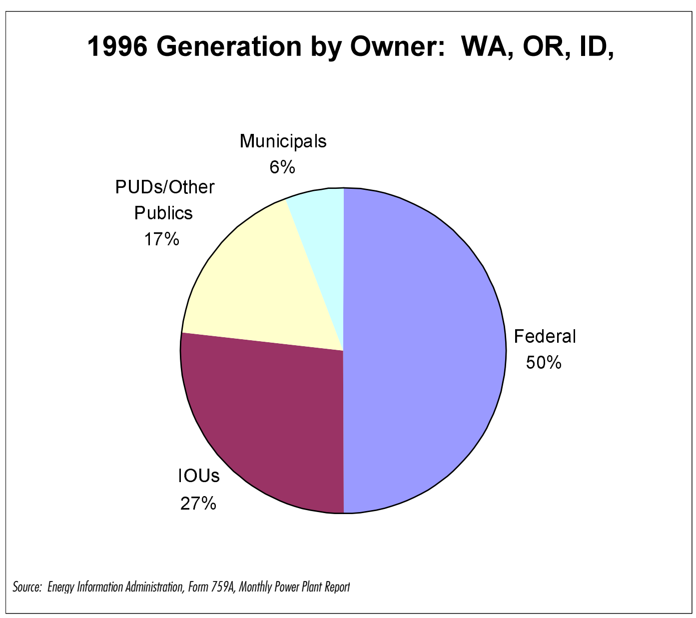
Publicly-owned generating resources account for nearly three-fourths of total electric generation serving Northwest consumers (again, it is impossible to calculate a mix of resources serving Washington customers alone). These resources were financed with tax-exempt debt and the cost of power from these resources to consumers does not include a rate of return (where that power is delivered by publicly-owned distribution utilities). As a result, and all other things being equal, the price of power from these resources is lower. Whether these price advantages represent cost advantages is arguable; profits to shareholders and different tax treatment for public resources may affect the distribution of costs and benefits rather than the magnitude of costs and benefits.

2.2.1.5 The environmental cost profile of Washington's generation

Most conventional forms of electrical generation carry significant environmental costs. Some of these costs are internalized in the form of pollution controls or fish and wildlife mitigation requirements, for example. Others, such as health impacts due to air emissions, remain external to the price of power, but are significant costs nonetheless. In Washington, significant environmental costs of the existing system include:

- Damage to fish and wildlife, particularly to threatened and endangered anadromous fish, associated with hydropower development

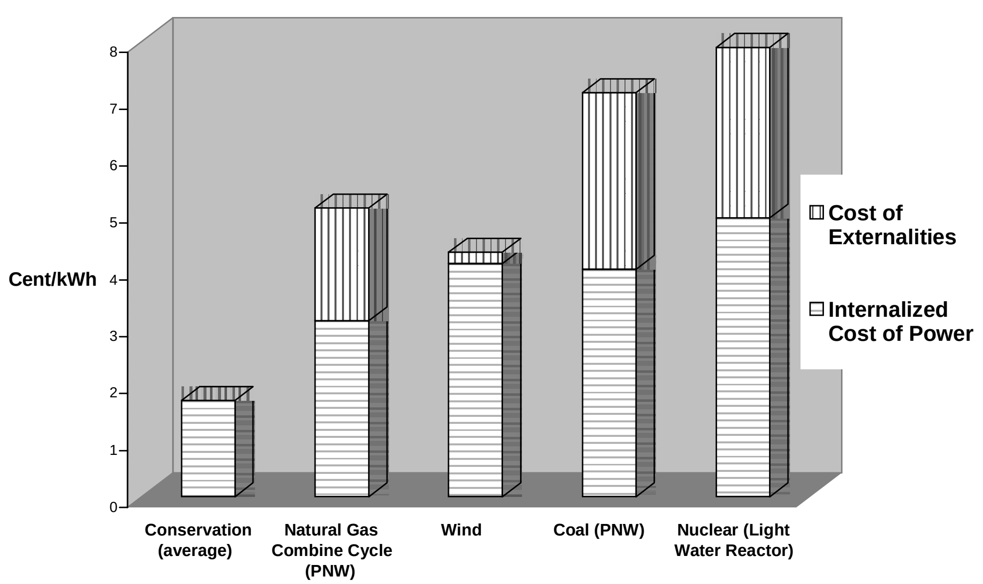
Figure 2.7



- ❖ Damage to fish and wildlife, particularly to threatened and endangered anadromous fish, associated with hydropower development
- ❖ Air quality and health impacts associated with emissions from fossil-fueled generating resources.
- ❖ Prospective or current changes to local ecosystems (including hydrology, forests, ocean temperatures, sea levels, etc.) and human health impacts associated with climate change, caused primarily by carbon dioxide emissions.
- ❖ The risk of health impacts associated with radioactivity released from nuclear power plants or their waste products.

Environmental costs are generally difficult to estimate in economic terms. However, the magnitude of these costs can have a significant impact on the overall cost-effectiveness of some resources. The following chart depicts the average internalized cost, environmental cost, and total cost of electricity from energy efficiency, gas, wind, coal, and nuclear power sources. (Both the internal and external costs of hydropower are somewhat more difficult to characterize; internal costs range widely by facility and external costs are very difficult to evaluate with any consistent methodology.) It should be noted that environmental cost estimates can vary widely by methodology. The exact estimates of environmental cost are not as important as the general indication that, where internal costs are comparable, consideration of external costs can make a substantial difference in the determination of which resources are cost-effective. (The chart uses the highest available environmental cost estimate for wind power and middle-range estimates for other resources.)

Figure 2.8 Costs of Electricity Generation (Internal and External)



Sources: Internalized Cost of Power, NWPPC , Draft Plan, 1996.
Cost of Externalities: EIA 1998 Annual Energy Outlook (natural gas, coal); Pace University, "Environmental Costs of Electricity", 1990. (nuclear); "Model Conservation and Electric Power Plan", Cavanagh and Shuman 1982 (wind)

Unlike generation, transmission costs for Washington utilities tends to be somewhat higher than the national average. The west, and particularly the Northwest, is more dependent on the transmission of power over the interstate, high-voltage grid than is the rest of the country. Much of the Northwest's generating capacity is located along the Columbia and Snake Rivers in eastern Washington and Idaho, or at coal fields in Montana or Wyoming, far from load centers in the Puget Sound area and the Willamette Valley.

Figure 2.8

Chart Washington transmission costs vs. other regions – waiting for EIA data

The region's generation is tied to load by an extensive high-voltage transmission network that is dominated by the federal system. Bonneville was authorized by the Bonneville Project Act of 1937 to "set rates to extend the benefits of an integrated transmission system and encourage the widest possible diversified use of Federal power." This authority was broadened by the Transmission System Act of 1974, which directed the BPA Administrator to build transmission "within the Pacific Northwest as he determines are appropriate and required to: (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units; (b) provide service to the Administrator's customers; (c) provide interregional transmission facilities; or (d) maintain the electrical stability and electrical reliability of the Federal system."

Bonneville has used this authority to construct an extensive federally-owned transmission system, including some transmission facilities that are only marginally connected to the FCRPS such as the 500 kV lines that connect Montana Power's Colstrip lines to the Northwest. As a result, the federal system accounts for some 80% of the region's high-voltage transmission wire.

2.2.2.2 Variations in Transmission Costs among Washington Utilities

On average, transmission accounts for around 10% of total costs for Washington utilities. However, costs for transmission vary greatly among Washington utilities. A great deal of transmission cost data was collected for the IndeGO proposal, the failed proposal to create an independent system operator that was developed by a number of Northwest utilities in 1996 and 1997. Because of the uniform cost allocation method chosen by the parties, the numbers developed for the proposal are probably the best data for comparison of transmission costs among utilities, at least for signatories to the IndeGO Memorandum of Understanding. In order to determine the total cost paid for transmission for each utility, IndeGO MOU signatories reported their transmission purchases and even transmission that is bundled as part of wholesale power sales, in addition to their revenue requirement for transmission that they own.

The IndeGO data, presented in the table below for utilities that participated in the 6560 study, depicts two distinct categories of utilities. The six utilities at the bottom of the chart generate large shares of their power needs at hydroelectric dams and transmit it to their distribution systems largely over transmission wires that they own. They make minimal use of high voltage interstate transmission facilities. These utilities pay between $17 and $21 per kW-year for transmission. The twelve utilities at the top of the chart make much greater use of the interstate transmission grid, and pay more than $26 per kW-year for transmission. These utilities either purchase large shares of their power over the Bonneville system (from Bonneville and/or other wholesale suppliers) or generate their own power at distant facilities such as minemouth coal plants in Montana and Wyoming. Some utilities, such as Nespelem, Snohomish, Grays Harbor and Orcas, must maintain their own transmission systems in addition to purchasing interstate transmission from Bonneville.

Another reason for the variation in transmission costs among Washington utilities is related to Bonneville's pricing policies. Bonneville has traditionally priced its transmission at a "postage stamp" rate, meaning that it charges all utilities the same rate regardless of where they are located on the transmission system. In addition, it has frequently entered into contracts ("General Transfer Agreements" or GTAs), with investor-owned utilities for use of their transmission systems to deliver federal power to publicly owned utilities that are not interconnected with the federal system. Bonneville entered into these contracts in order to avoid the expense of constructing duplicate facilities to reach preference customers. These costs have historically been classified as transmission but collected as part of bundled power sales. However, in 1996, when Bonneville allowed its customers to diversify a percentage of their loads, the cost of the GTAs was included in BPA's power rates. It is currently unclear how the $40-50 million in GTA costs will be collected during and after the BPA rate period beginning in 2001.

Table 2.1 Transmission Costs for 6560 Participants, per IndeGO Proposal

	$ per kW-year
Nespelem Valley Electric Coop*	$40.44
Snohomish County PUD	$33.27
Grays Harbor County PUD*	$32.50
PacifiCorp	$31.65
Orcas Power and Light*	$31.43
Inland Power and Light*	$30.53
Puget Sound Energy	$30.10
Benton County PUD*	$29.45
Clark County PUD*	$28.79
Benton REA*	$27.77
Franklin County PUD*	$26.67
Parkland Light and Water*	$26.46
Cowlitz County PUD*	$21.33
Seattle City Light	$19.76
Grant County PUD	$19.58
Chelan County PUD	$19.52
Washington Water Power	$18.86
Tacoma Power	$16.80

Source: November 26, 1997 IndeGO Proposal

Note: Costs for utilities that did not participate in the IndeGO data collection (marked with an asterisk) are rough estimates prepared by the IndeGO workgroup of these utilities' total costs for transmission using IndeGO methodology.

2.2.2.3 External Costs of transmission

The environmental costs associated with the transmission system are primarily related to siting concerns. High-voltage transmission facilities require wide rights-of-way from which all vegetation must be cleared and along which roads must be maintained. Typical issues that would be raised in an environmental impact statement therefore include the impact on wetlands, wildlife, and wilderness areas. Visual impacts are of great concern to communities affected by high-voltage transmission lines. Some studies suggest that prolonged exposure to electromagnetic fields (EMFs), such as one would experience living near a high-voltage transmission line, may cause cancer. Other studies have found no link between electromagnetic fields and cancer. Research continues into whether such a link exists.

2.2.3 Distribution

2.2.3.1 Washington Distribution Costs Compared to National Averages

Distribution costs for Washington utilities tend to be somewhat lower than the national average on a per kWh basis. This is due primarily to the concentration of large industrial users of electricity. Large users have little need for low-voltage distribution facilities. However, since they consume large quantities of power, total distribution costs (the numerator) are spread over a larger base of power sales (the denominator), resulting in a relatively low average distribution cost (the fraction).

Table 2.2 Distribution cost indicators for Washington utilities

2.2.3.2 Variations in Distribution Costs among Washington Utilities

Differences in density are commonly cited as the primary reason why distribution system costs vary among utilities[*]. Utilities with a large proportion of their customers in rural areas have more miles of line to construct and maintain on a per customer basis. This makes costs higher for utilities that are predominantly rural. The data collected for the 6560 and 2831 studies show that there is a strong countervailing factor, however. Constructing and maintaining distribution lines is more expensive in urban areas than in rural areas on a per mile basis, due to higher costs for rights of way, higher percentage of wires undergrounded, more expensive labor, and a number other reasons. This is illustrated in the first two columns of the table above. Cost per mile

Figure 2.10

Chart Washington distribution costs vs. other regions – waiting for EIA data

* Note, however, that these data do not include figures from the state's most rural, lowest-density utilities, which where not required to report under ESSB 6560 or HB 2831.

shows a strong inverse relationship to density.

The result is that the cost per kWh doesn't vary nearly as much as one might expect, at least among the utilities that reported data for the unbundling study.

Perhaps a better way to compare distribution system costs across utilities is to look only at the distribution system costs that are allocated to residential customers. This

Table 2.2 Distribution cost indicatiors for Washington utilities

	Density, # of Customers per Mile	Total Distribution Costs, $ per Mile	Total Distribution Costs, ¢ per kWh	Residential Distribution Costs, ¢ per kWh	Residential Distribution Costs, $ per Customer
Grant County PUD	11.4	$7,241	0.82	1.26	$285
Grays Harbor PUD	27.1	$10,200	1.39	1.76	$287
PacifiCorp	27.7	$13,168	1.50	2.14	$248
Chelan County PUD	29.2	$16,653	0.72	2.21	$480
Benton County PUD	30.4	$12,008	0.89	1.45	$303
Puget Sound Energy	48.0	$18,037	1.49	2.03	$265
Snohomish County PUD	48.8	$23,871	1.85	2.39	$360
Tacoma Power	86.8	$27,724	0.85	1.63	$235
Seattle City Light	199.4	$81,290	1.60	1.98	$206
Clark County PUD	—	—	0.83	1.41	$234
Washington Water Power	—	—	1.36	1.70	$209

Sources: ESSB 6560 Data Request, HB 2831 Unbundled Cost Reports

Notes: Clark and WWP did not report distribution system miles.

should correct for the fact that some utilities have higher concentrations of industrial customers, which would result in lower system-wide costs on a per-kWh basis. Residential distribution costs vary less than total distribution costs. It is difficult to draw any firm generalizations about why these costs vary, other than that rural, eastside utilities such as Grant and Benton PUDs show the lowest costs. However, customers of these utilities consume a lot more electricity per year than customers in more urbanized areas, in part because they have less access to natural gas for heating. The result is that customers in those areas pay more, on an annual basis, for distribution services despite the lower unit price.

2.2.3.3 External costs of distribution

The environmental costs associated with the distribution system are similar to those described above for transmission wires. Concerns about visual impacts, in addition to reliability considerations, have caused most utilities to begin putting wires underground, at least for new developments. Concerns about EMFs have generated resistance to siting facilities such as substations in neighborhoods.

2.3 Trends

Trends affecting electric service costs are grouped into six focus areas:

1) Wholesale market developments
2) Retail market developments
3) Load/resource balance (the relationship over time between demand and supply)
4) Environment
5) Technology
6) Fuel cost

2.3.1 Wholesale market developments

2.3.1.1 Federal Policy Changes and the Introduction of Wholesale Competition

Perhaps the most important and far-reaching trend affecting electric power costs today is the significant change that has taken place in the market structure for power generation. Beginning in 1978 with the passage of the federal Public Utility Regulatory Policy Act (PURPA), non-utility generators have played a growing role in developing new generating resources. PURPA required investor-owned utilities to purchase power from non-utility generators if the cost was less than the utility's own cost to build new generation. Although PURPA had a limited impact on most Washington utilities, it opened the door for companies other than utilities to build and own generation.

This change was accelerated by the passage of the federal Energy Policy Act in 1992. EPACT was intended to create a fully competitive wholesale market for generation, and spurred a number of developments that furthered that goal. One of these developments is the formation of regional transmission associations (RTAs) in the western interconnection to facilitate access to the regional transmission grid.

In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, entitled "Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities". Order 888 requires transmission owners to offer transmission services to other companies under the same terms and conditions that they offer it to themselves. It also encourages the formation of independent system operators (ISOs) to provide open access to the transmission system under a grid-wide tariff that would apply to all eligible users. All jurisdictional utilities are required to file open access transmission tariffs with FERC that meet the specifications laid out in the order, and to provide service to themselves and to other companies under the terms of those tariffs.

These developments have greatly increased the ability of generators to gain access to the transmission grid. The result has been the development of active short-term markets for electric energy. Power is now traded on an hourly basis at trading hubs such as the Mid-Columbia bus, on a day-ahead basis on the California Power Exchange, and in the form of futures contracts on the New York Mercantile Exchange. Utilities now have a ready market in which to sell surplus generation to other utilities or to purchase power from other utilities or non-utility generators.

The development of active short-term markets, in conjunction with enhanced access to the transmission grid, may tend to lower the overall cost to society of providing electric generation by maximizing the aggregate efficiency of the existing bulk power system. That is, a robust market should help to ensure that whenever a low-cost resource and a high-cost resource are both available, the low-cost resource is called upon first.

One of the features of these markets is price volatility. Commodity markets are notoriously volatile, as prices continuously adjust to balance supply and demand at any given time. Electricity markets are likely to be particularly volatile, especially on an hourly basis, because electricity cannot be stored, meaning that supply and demand must balance instantaneously. This means that utilities have very little time to arrange for alternate supplies in the event of an emergency. One such emergency occurred in the Midwest during June of 1998, when market prices soared to over $7.00 per kWh. This extreme volatility was caused by a series of extraordinary events including a heat wave, generating unit outages, transmission constraints, and defaults on power supply contracts by two power marketers. The combination caused confidence in the market to fail, leading to panic buying of whatever power was available.

This volatility does not mean that power markets necessarily result in higher costs than traditional utility planning, in which enough capacity is built to meet an administratively determined probability of being able to meet all loads. Indeed, market volatility might result in capacity savings if price-sensitive customers (those that have the ability to modify their consumption based on price) purchase power on the open market. These customers would be free to make whatever arrangements they wished to hedge their risk against price volatility, while the utility would be freed from the obligation to manage the risk on behalf of those customers. On the whole, this may be a less costly way to balance supply and demand in peak periods than the traditional practice of building utility capacity to meet infrequent peak demands. It does, however, allow for conspicuous price swings.

2.3.1.2 Effects of wholesale competition on BPA and Federal Columbia River Power System

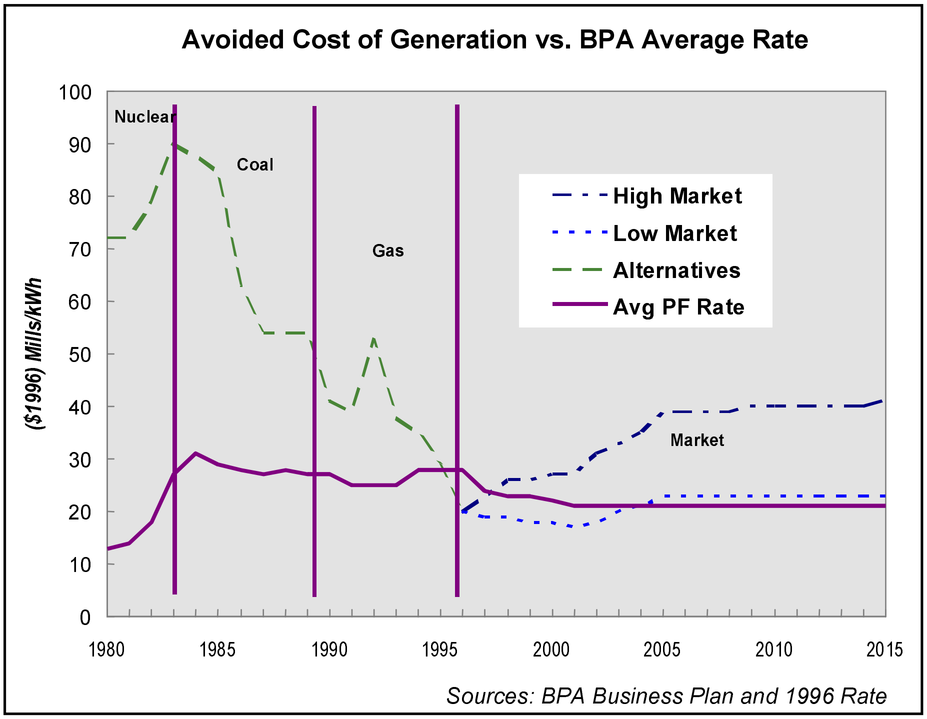
Although Washington has not initiated any significant changes in its retail market, Northwest states were among the first to experience significant effects from the introduction of wholesale competition. This is due to the tremendous importance of the Bonneville Power Administration in the state. BPA is a federal power marketing agency that operates exclusively at the wholesale level (with the exception of its Direct Service Industrial customers, to whom BPA provides retail service). The agency provides approximately half of the power consumed in Washington and operates 80% of the high voltage transmission in the State.

The effects of wholesale competition on BPA have been rapid and dramatic. As the chart below shows, the price of power in the wholesale market plummeted in the early 1990s, reaching and briefly falling below BPA’s price in 1995. It is worth noting that this challenge to BPA’s competitiveness was not caused by increasing costs at BPA. BPA’s prices have stayed virtually flat in nominal terms and declined somewhat in real terms since the dramatic increases associated with the WPPSS projects in the early 1980s. The “competitiveness crunch” was caused almost entirely by reductions in the price of alternative power sources.

When the price of alternative resources approached BPA prices, BPA embarked on a series of dramatic and controversial changes in an effort to improve its competitive position. These changes included:

- ❖ Seeking a cap on fish and wildlife expenses and an exemption from any Endangered Species Act or other environmental requirements that would push fish and wildlife expenses higher.

Figure 2.11



- ❖ Terminating its contract to pay for construction and operation of the Tenaska gas-fired generating project.
- ❖ Reversing its preliminary commitment to British Columbia to purchase the "Canadian Entitlement" – power that returns to Canada under the terms of the Columbia River Treaty.
- ❖ Eliminating most of its energy efficiency investments.
- ❖ Large reductions in staff and contractors.
- ❖ Curtailing the Residential Exchange agreements through which BPA extended the benefits of the FCRPS to the residential and small farm customers of investor-owned utilities, including Puget Sound Energy.
- ❖ Developing new marketing strategies that were viewed by some as inappropriate competition with the private sector.
- ❖ Signing transmission contracts and power contracts with the Direct Service Industries that seek to preclude future recovery of stranded costs from those customers.

Each of these steps met with strong opposition from one or more stakeholder groups. With growing frequency throughout 1995, this opposition was brought to the attention of Congress and executive agencies in Washington, D.C.. Sensing that the growing discord in the region was undermining the region's ability to retain the benefits of the federal system for Northwest consumers, the Northwest Congressional delegation and the Department of Energy urged the four Northwest Governors to develop a plan for the future structure of the regional power system. In response, the Governors convened the Comprehensive Review of the Regional Energy System in 1996. The Steering Committee for the Comprehensive Review recommended a variety of changes with respect to the federal power system. The major changes included a strategy for marketing the output of the FCRPS to Northwest customers by subscription; formal separation of BPA's transmission and generation functions; and formation of an independent system operator for the transmission system, including federal transmission.

Since those recommendations were issued:

- the Northwest Power Planning Council convened a cost review panel to recommend further reductions in BPA's costs. BPA has agreed to try to implement most of these recommendations. The final recommendations of the Cost Review are included as Appendix 2-1
- the Governors appointed a Transition Board to oversee implementation of the Comprehensive Review's recommendations. The Transition Board has focused exclusively on the recommendations with respect to BPA's power and transmission operations. It has developed a proposal for recovering stranded costs in the event that BPA's costs exceed market rates and a proposal for subjecting BPA's transmission rates to review by the Federal Energy Regulatory Commission essentially equivalent to the review applied to investor-owned transmitting utilities.
- [*revise as necessary* BPA has begun the process of offering subscriptions for cost-based power, according to a proposal issued in September of 1998]
- BPA is scheduled to begin a rate case that will further define the terms and conditions of those subscription contracts in [xxmonth] of 1999.

Another important trend affecting the region's ability to sustain the legal right to preferential access to cost-based power from the federal system is the growing pressure to redistribute the benefits of the FCRPS more broadly. This pressure has existed for decades. However the pressure may have intensified in recent years[1] due to a variety of factors, including:

- The evolution toward competition in wholesale, and, to a lesser extent, retail power markets. With power prices increasingly subjected to market forces, the rationale for continuing to constrain marketing of federal power at cost to a particular geographic region may appear to be eroding.
- The general trend in other countries and the U.S. away from large public enterprises and toward privatization.

- Growing concern over how to pay for the large federal entitlement programs as the population ages and the consequent pressure to convert federal assets to cash and/or increase the return to taxpayers from those assets.
- The increasingly organized advocacy of the Northeast-Midwest Coalition, a large group of members of Congress who call for selling federal power at market rates.
- The increasingly open nature of transactions throughout the Western power grid and the proliferation in the number of buyers and sellers seeking access to the lowest cost alternatives.
- The growing frequency with which regional power issues are debated in Washington, D.C. and the perception that federal taxpayers may be exposed to nuclear debt, fish costs, or other costs that BPA fails to recover in its rates.

If these pressures converge in a way that allows redistribution of the benefits of the FCRPS, Washington's power prices could rise substantially. These pressures will almost certainly come to bear in the context of a national restructuring bill. They are likely to persist even in the absence of such a bill.

2.3.1.3 Effects of both wholesale and retail competition on the connection between existing generation and "native loads"

Historically, electric generating resources have been built or purchased to serve a particular set of consumers. Those consumers had few if any options for electric service and their utilities were required to serve their loads. In this environment, consumers could generally expect to pay the costs and receive the benefits of a specific set of electric generating resources that were built to serve them.

With growing competition in both the wholesale and retail markets in the Western grid and major realignments of the vertically integrated utilities, this connection between customers and resources is becoming increasingly tenuous. Typically, the erosion of this connection has manifested itself as a "stranded cost" issue: When the connection between customer and resource is broken by competition, who bears the costs associated with that resource which cannot be recovered through market rates (stranded costs)? In Washington, the more significant issue may be on the other side of the coin: When the connection is broken, who reaps the benefits that accrue to resources that are worth more than they cost ("stranded benefits")? Resolution of these questions may substantially affect the cost of electric service in Washington. (These questions are arguably less of an issue in the case of public power, since there are no shareholders to bear stranded costs or reap stranded benefits. However, the prospect of redistribution of the benefits of low-priced public resources is still a concern.) Since most the resources used to serve Washington consumers are below market, erosion of the connection between "native resources" and "native loads" will tend to increase costs for Washington consumers.

2.3.2 Retail market developments

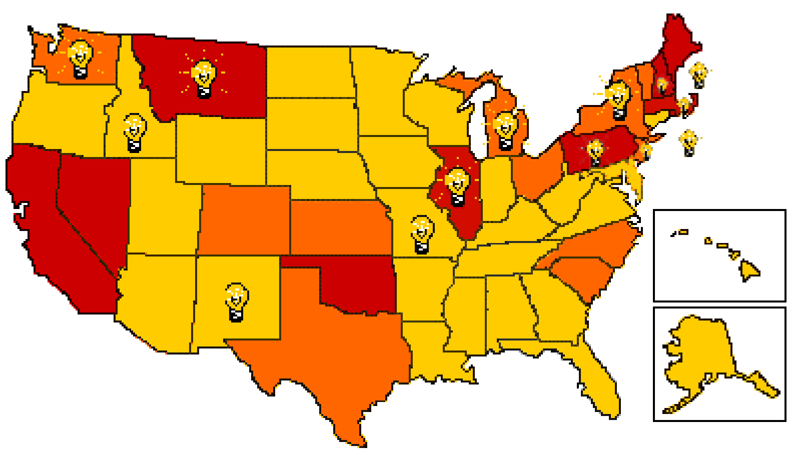
2.3.2.1 Federal and state restructuring initiatives

Congress considered mandating retail access in its deliberations on the 1992 Energy Policy Act, but elected to defer the issue pending state action. Subsequently, federal restructuring legislation in various forms has been introduced but not yet seriously debated in Congress. Appendix 2-2 provides a comparison of some of the major features of the federal electric restructuring bills that have been introduced to date.

According to the Edison Electric Institute, all 50 states and the District of Columbia have initiated "legislative or regulatory processes examining retail competition, de-regulation, restructuring, and/or alternative forms of regulation for the electric utility industry."[2] The National Regulatory Research Institute also confirms that all states have engaged in some restructuring-related activity.[3]

The impetus for retail restructuring came largely from industrial customers in states with high power prices, like California and the New England states.[4] Seeing the growing disparity between retail power rates and the price of power in wholesale markets, these customers sought direct access to lower cost power supplies. With very few exceptions, gaining this access meant changing state laws and/or regulatory requirements to compel utilities to deliver power from the provider of the customer's choice.

Figure 2.12 Status of Electric Utility Restructuring Activities



Retail Wheeling Legislation Passed
Retail Wheeling Legislation Proposed
Legislative or Regulatory Activity
Indicates states where pilot programs have been initiated or approved

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Even the first states to restructure are still in the early stages of implementing their restructuring laws or administrative orders. (A detailed comparison of state electric restructuring legislation provisions is provided in Appendix 2-3.) No meaningful conclusions can yet be drawn from the experience in these states with respect to the effect of retail restructuring on electric service costs. The prospects for future federal and state restructuring efforts and the pace of those efforts remain unclear.

Most of the arguments about whether retail restructuring will reduce electric service costs remain conceptual rather than empirical. These arguments are briefly characterized in Section 3 on retail market strategies.

2.3.2.2 Retail market developments in Washington and the Northwest

At the end of 1996, the Comprehensive Review of the Regional Energy System recommended that the four Northwest states restructure their retail electric markets by July of 1998.[5] Montana is the only state to have enacted restructuring legislation and has begun to implement retail choice. Restructuring bills were considered by the Washington and Oregon legislatures in 1997. (In Oregon, the action has shifted from the legislature to the Oregon Public Utility Commission, where PGE/Enron has filed a restructuring plan.) The issue was considered again by the Washington legislature in 1998, but no comprehensive restructuring bills were introduced. Bills requiring large utilities to account separately for the different components of electric service (HB 2831) and requiring state agencies to study various aspects and trends in the industry (ESSB 6560) were passed. This study is the product of the latter bill.

Notwithstanding the lack of any legislative action to restructure Washington's retail electric market, that market is changing substantially. While utilities have not been compelled to deliver power from alternative providers, they are nevertheless experiencing and responding to significant competitive pressures and opportunities. Some of these changes, and some of their potential implications for electric service costs, are described below:

2.3.2.2.1 Pilot retail access programs

Several utilities have conducted pilot retail access programs, including Puget Sound Energy, Washington Water Power, and Clark PUD. Prices offered in pilots may bear very little relationship to prices in a system-wide retail access environment. Pilots have generally been structured to test operational issues, rather than to test the effects of competition on costs or prices.

2.3.2.2.2 "Non-traditional" rates

Most utilities have provided some form of either direct access or market-based rate schedule to their largest industrial customers. These have resulted in substantial recent declines in industrial rates. However, some customers are opting out of market-based rates and returning to conventional regulated service as wholesale market prices increase. We cannot judge whether this retail market activity has resulted in either cost reductions or cost shifts. To the extent that these customers have enjoyed declining rates, this may be due to declining costs in the wholesale market which would ultimately flow through to retail customers even in the absence of market-based rates for industrial customers.

In response to the data survey for this study, fifteen utilities provided data on “non-traditional” rate offerings. These rates generally reflect either a market-based price or an agreement by the utility to purchase market power on behalf of the customer, as opposed to the traditional practice of charging rates based on the average cost to serve the customer class. The data indicate that cost pressure due to declining wholesale market prices can have a direct impact on utility rates, even in the absence of mandatory retail access.

Table 2.3

	Share of Large Customer Load Taking Service Under "Non-Traditional" Rate Schedule
1995	*19%*
1996	*25%*
1997	*47%*

Source: ESSB 6560 Data Request

Seven of these fifteen utilities offered “non-traditional” service to large customers in 1997. Five of the seven have seen participation in non-traditional service grow rapidly since 1995. A total of 418 customers were taking “non-traditional” service in 1997, accounting for nearly half the industrial load of the reporting utilities.

The average price at which “non-traditional” service was offered was 2.8¢ per kWh, more than half a cent lower than the average of the lowest industrial rate. This represents an average discount of 17% off the lowest reported industrial rate. The largest reported discount was 36% off the lowest industrial rate.

Table 2.4 “Non-Traditional Service” Rate Information (Average of Reporting Utilities)

Average rate for “non-traditional” service(¢/kWh)	2.79
Average of lowest reported industrial rate (¢/kWh)	3.39
Absolute difference from lowest industrial rate (¢/kWh)	-0.60
Percent difference from lowest industrial rate	-17%

Source: ESSB 6560 Data Request

Including these non-traditional rates, large customers have seen an average rate decrease of around 5% since 1995, while residential rates have remained relatively flat. Of the fifteen utilities reporting, thirteen reduced rates for their industrial customers between 1995 and 1997, and eight reduced the rates of their residential customers[3]. Industrial rates declined relative to residential rates for thirteen of the fifteen utilities. (The distributional impacts of non-traditional rates is discussed in Section 4.)

2.3.2.2.3"Diversification" of consumer-owned utility purchases

Many consumer-owned utilities took advantage of BPA's offer to "diversify" their resources by reducing their reliance on BPA in 1996. In most cases, they passed on the cost savings associated with those contract changes to industrial customers. This was a way to pass through the benefits of low market prices without formal retail access.

2.3.2.2.4 Variations in tax exposure

By contracting directly with out-of-state suppliers, a few customers may avoid paying state and local taxes associated with utility service. We do not know how this may affect costs, since it either results in shifting of the tax burden or reduction in public services funded through taxes. Since the taxing jurisdiction presumably judges the benefits of those services to exceed the cost, reductions in public service do not equate with reductions in cost. In any event, the present magnitude of this cost issue does not appear to be very large, unless and until many more customers gain access to out-of-state suppliers. (See Section 4.)

2.3.2.2.4 Aluminum companies diversify supplies

The state's aluminum companies have diversified their resources and are now purchasing roughly 25% of their power from sources other than BPA. Like their BPA purchases, most of these purchases are untaxed at the state and local levels, as they do not flow through a retail electric utility. These companies also have transmission contracts with BPA that give them direct access to the wholesale power market. These changes have generally lowered prices to these customers.[6] Their effect on total costs is not known.

2.3.2.2.5 Declining achievement of energy efficiency, renewable resources, and low-income weatherization goals

Utility investment in energy efficiency, renewable energy, and low-income weatherization is declining rapidly. (See Section 9). While lower wholesale power costs explain some of this decline, much of it is due to real or perceived competitive pressure on utilities to minimize rates. The rapid decline in BPA funding for these initiatives has generally not been offset by increased funding from retail utilities. Insofar as these investments secure cost-effective resources or otherwise produce benefits that exceed their costs, declining investment may raise total costs. For example, the Northwest Power Planning Council estimates that failing to capture cost-effective energy efficiency improvements that market forces will not capture would cost the Northwest region roughly $1.8 billion over the next 20 years.[7]

2.3.2.2.6 Competition and cost-cutting pressure raises concerns with respect to reliability

Reliability-related trends are discussed at length in Section 8 of this report. One concern is that pressure on integrated utilities to cut generation costs may cause underinvestment in maintenance and operation of delivery systems and thereby compromise their reliability. These utilities may also face uncertainty regarding their ability to recover the cost of reliability-related investments. This pressure may be particularly acute in the current environment of uncertainty about future market structure. This is because integrated utilities providing bundled service may respond to competitive pressure by cutting costs in any component of service, whereas formal restructuring might narrow the scope of competition to those functions (especially generation) that are best suited to competition. We have no data that either supports or disproves a trend toward underinvestment in reliability.

2.3.2.2.7 Transition costs

Anecdotal information suggests that utilities are experiencing some costs associated with preparing for the possibility of greater competition in the future. For example, enhanced billing and metering technology, software changes, and the costs of compliance with HR 2831 and ESSB 6560 were all cited by utilities as costs related to competition or the prospect of competition. We have no data on these costs.

2.3.2.2.8 Corporate realignment and reintegration

Investor-owned and consumer-owned utilities are engaged in a variety of mergers, acquisitions, realignments, and new partnerships to position themselves to take advantage of strengths, shore up vulnerabilities, and compete in new markets. Some large utilities (such as PacifiCorp) appear to be focusing primarily on their wholesale marketing activities, while others (such as Puget Sound Energy) are selling or plan to sell their generating assets to concentrate on expanding their range of activities in the retail market. Consumer-owned utilities including Chelan PUD and Snohomish PUD have formed marketing partnerships with investor-owned utilities or their affiliates. Public utilities are also beginning to provide and/or seeking authority to provide a wider range of services, including gas and telecommunications.

The effects of these trends on costs are far from clear. In general, mergers and acquisitions are nominally motivated by economies of scale or scope and the potential for cost reductions through the integration of complementary services. However, they may also be formed to take advantage of opportunities to exert horizontal market power. Some have expressed concern (and others have expressed hope) that partnerships formed for wholesale marketing may lead to wider access of consumers across the western grid to the benefits of low-priced resources that currently serve Washington consumers. (From a Washington perspective, this could raise costs; from a west-wide perspective, it could shift costs and benefits. Also, it should also be noted that increased wholesale marketing of Northwest resources does not by itself redistribute the *benefits* of those resources. Unless existing laws and regulation that link Washington consumers to those benefits are changed or weakened, Washington consumers may benefit from increased wholesale marketing, insofar as wholesale revenues are credited against revenue requirements to lower retail rates.) Expansion of the range of services offered by consumer-owned utilities may lower costs for some services in some areas, but also raises concerns about competition between public and private service providers.

2.3.2.2.9 Uncertainty regarding cost recovery and market structure

Uncertainty regarding future market structure has consequences that may affect electric service costs as much as market structure changes themselves. For example, in the face of substantial uncertainties about their future customer base, utilities are generally disinclined to make long-term investments. To the extent that this disinclination is a considered response to uncertainties regarding such factors as technological change, it could tend to help minimize costs. However, to the extent that aversion to long-term investment reflects uncertainty about the legal and regulatory framework in which utilities will do business in the future, it may tend to increase costs over time. Inability to make long-term investments could drive costs up and increase volatility by making it difficult to find capital for projects that ensure adequate supply, efficiency, and reliability in the future (See Section 2.3.3). Such uncertainty also tends to produce a bias against strategies with high proportions of capital costs to operating costs (such as energy efficiency), even when those strategies are the least costly ones available. Without rendering judgement on how these trends will ultimately affect costs, it is important to restate that the concerns above are a function of uncertainty about future market structure rather than any particular change in market structure.

The changes described in **2.3.2.2** may substantially affect not only the total cost of electric service, but also the distribution of costs, reliability, customer service, and environmental performance – precisely the issues highlighted by the Legislature as sources of concern and study in ESSB 6560. This suggests that even if “restructuring” per se does not occur, many of the issues it raises are with us today.

2.3.3 Load/resource balance

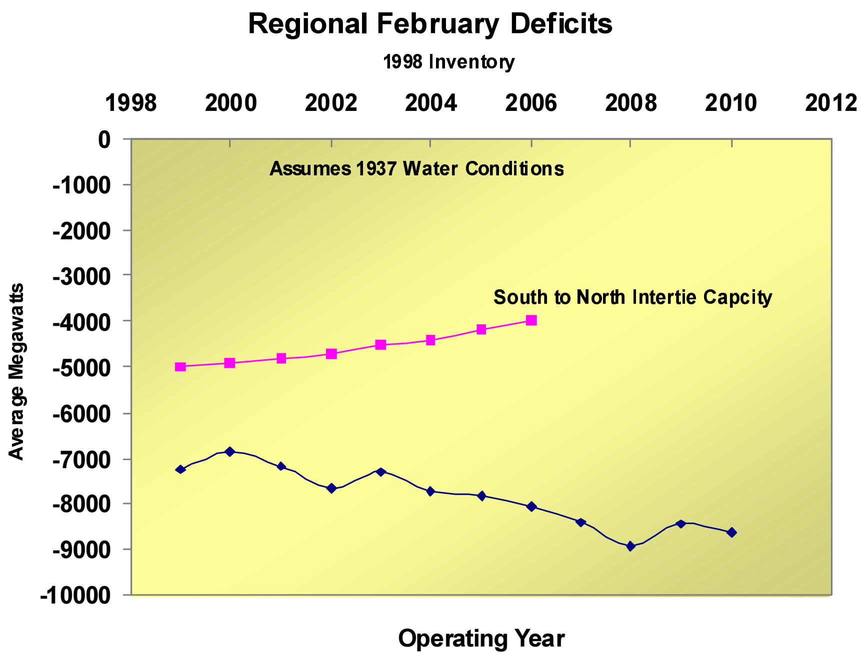
Recent analyses of the Northwest’s power system loads and resources indicate that in some months, the demand for electricity could outstrip both the capability of existing resources within the region *and* the ability to import additional power. This analysis was presented in the Bonneville Power Administration’s “White Book.” It assumes continued “medium” growth (about 1.5 percent per year) in the demand for electricity and historic “worst case” conditions for hydroelectric production. Figure 2.13 provides an overly simplified view of the issue that was presented to the Northwest Power Planning Council.

Figure 2.13 shows the monthly regional deficits (Current resources minus projected loads) that would occur in February with extremely adverse hydro conditions as represented by the conditions that existed in 1937. The deficits increase (become more negative) as loads grow in the region. Also shown is the approximate south to north transfer capability of the North-South intertie, the main source of imported power. Its capability decreases with time as a result of load growth in the Northwest which affects the ability to move power from south to north on the intertie. A similar but somewhat more severe problem exists when considering the ability to meet sustained peak loads. Those are the average loads during the peak ten hours per day for a five day work-week. During such a period, loads increase and generating capability decreases due to extreme weather conditions.

The representation of the problem shown in Figure 2.13 is simplified in many respects. One of the most important is that it does not reflect the effects of year to year, month to month variations in hydro conditions. The Columbia River System cannot store the full annual runoff of the basin and the flexibility to use existing storage to maximize power production is increasingly limited. The difference in the hydro system's power capability from the driest to the wettest years is as much as 8000 average megawatts.* These variations affect the probability that we will actually experience deficits in any given year.

To begin to assess the probabilities, Northwest Power Planning Council staff have looked at how frequently the regional deficit would exceed import capabilities in each of the winter months (December, January and February), based on the 50 water years in the historical record (1929-1978). This analysis was done for three different future operating years, again assuming current regional resources and medium load growth. This is shown in Figure 2.14.

Figure 2.13



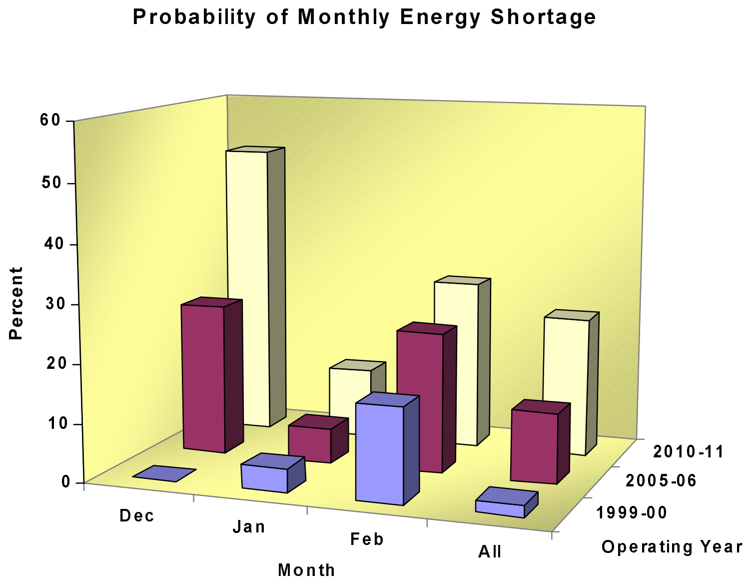
This figure indicates that, in the next few years, the likelihood of a shortage in any given month is relatively small. For the 1999-2000 operating year, the likelihood of deficits in February is only about 15 percent. By 2010-11, however, the likelihood of a deficit for December grows to roughly 50%.

These deficits have been forecast for a few years now. But the magnitudes are increasing and the time available in which to take actions to avert a shortfall is becoming more limited.

In its preliminary look at this issue, the Northwest Power Planning Council reports that addressing these shortages is complicated by the changing nature of the utility industry. When utilities were less subject to competition, they acquired assets to

* As a point of reference, the annual electricity loads of the City of Seattle are slightly over 1000 average megawatts.

Figure 2.14



provide an industry-standard level of reliability, including reserve generation and a robust transmission and distribution system. Regulators allowed them to recover the cost of those assets in rates, even when some of those assets would be used very infrequently and cause increases in rates. With the prospect of competition, many utilities may be reluctant to include in their rates the cost of acquiring sufficient resources to serve loads that may have no obligation to remain on their system.

Additionally, a growing number of power suppliers are not regulated utilities but marketers or brokers who buy and sell power on the wholesale market without necessarily owning resources. Or they may be independent power producers without a captive customer base that assures them recovery of their fixed costs. Some utilities are selling off their generating assets. The result of these trends is increased risk for companies that acquire new generating resources.

This market risk may be compounded by the uncertainty associated with fluctuating output of the hydropower system. Developers have neither a stable market for the output of their resources, nor a guarantee that water conditions will be sufficiently unfavorable that their output is needed in any given month or year. This means that they may have to recover the costs of developing new resources over relatively short and highly unpredictable schedules of operation. The Northwest Power Planning Council has initiated an analysis to determine: 1) Whether exisitng market incentives are sufficient to bring about the development of new resources (generation, transmission or demand side); and 2) If market incentives are not adequate, what alternatives are there for ensuring the Northwest an adequate, reliable power supply?

The issue of generation adequacy and its affect on reliability is discussed further in Section 8.0.

2.3.4 Environment

Environmental costs are a significant component of the total costs of electric service. Nationally, electric power generation accounts for two thirds of total emissions of sulfur dioxide, one third of total emissions of nitrogen oxides, and one third of total emissions of carbon dioxide. Electric power production also produces nuclear wastes, which pose risks to ecosystems and human health. It also has substantial impacts on water quality and quantity.

Washington and the Northwest are particularly familiar with the environmental costs associated with hydropower. The financial cost and effectiveness of current and proposed measures to reduce those environmental costs are the subjects of intense debate. However, while it is impossible to quantify the economic value of hydropower's environmental impacts with any precision, these costs are clearly a major factor in decisions about the region's existing and future electricity supplies.

In evaluating environmental trends that affect the cost of electric service, it is useful to distinguish between *internal* costs and *external* costs. Internal environmental costs are those that are included in rates paid by consumers, such as the costs associated with installing air pollution control equipment required by the Clean Air Act or fish ladders required as conditions of hydropower licenses. External costs are those that are borne in the form of environmental damage such as habitat degradation or human health impacts. For example, even though emissions of various pollutants from fossil-fueled generators are regulated, the residual emissions cause some human health impacts such as lung disease. The costs of complying with air quality regulations are internal, but the health impacts that occur even after legal requirements are met are external.

This distinction between internal and external costs is important in order to clarify the difference between absolute changes in the *magnitude* of environmental costs and changes in the *distribution* of environmental costs between internal and external categories. For example, measures required to support recovery of endangered salmon stocks may *shift* costs from the external category to the internal category. Prices may rise due to such internalization. However, such price increases do not generally reflect increases in total costs. Internalization of environmental costs increases total costs only if the cost of the mitigation measures exceeds the cost of the environmental damage being mitigated. It is often difficult or impossible to compare the cost of mitigation with the cost of environmental damage. However, when mitigation is required, society has implicitly made a broad, often political judgement that fixing or preventing the environmental damage is less costly than living with it. If we collectively do not accept this judgement, then pressure builds to change the laws or regulations that require mitigation. However, where we accept this judgement, then internalization may tend to <u>reduce</u> costs, by sending price signals that more accurately reflect total costs.

The trends discussed below have implications for both the magnitude of environmental costs and the distribution of costs between external categories (impacts to the environment) and internal categories (mitigation measures that affect power prices.) There are a great many environmental trends that may affect electric service costs. However, three trends seem most likely to have a substantial impact on the environmental costs of electric service in the foreseeable future: a) declining populations and extinction of wild anadromous fish, b) global climate change, and c) increasing competition in electric power markets.

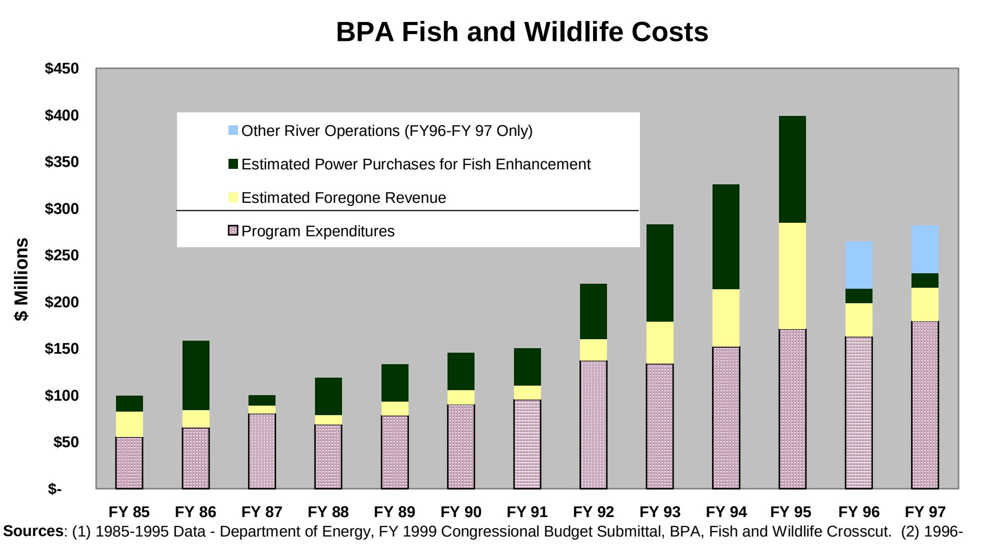
ery stocks. On many rivers including most notably the Snake and the Columbia, dams and hydropower production also appear to play a significant role in the decline of these populations. The trend in total environmental costs attributable to dams can be argued either way.

On the one hand, costs may be rising as genetically distinct stocks become extinct or near extinction. When a run of fish approaches or falls below the threshold where it can continue to survive as a separate stock, additional costs are incurred in the form of lost genetic diversity, cultural values, and future economic opportunities.

On the other hand, improvements to fish passage facilities, flow regimes, hatchery practices, habitat management, and other biological conditions for fish in recent years suggest that some environmental costs have been mitigated. Many of these costs have been internalized in power rates. To the extent that these mitigation measures have been effective (a hotly contested issue), environmental costs of hydropower production are presumably lower than they would have been absent these measures. Whether the improved conditions attributable to these measures have been worth their costs is also a bitterly disputed issue, in light of continued decline in most wild stocks.

The dollar value of damage to fisheries from hydropower production cannot be assessed with any precision. The cultural, biological, and esthetic values at stake are very difficult to quantify and value economically, and the precise affects of hydropower production cannot be definitively separated from other factors that adversely affect these stocks. However, it is clear that more environmental costs associated with anadromous fish decline are being internalized in power rates. The graph below shows the increases in BPA's fish and wildlife expenditures over time as reported in

Figure 2.15



Sources: (1) 1985-1995 Data - Department of Energy, FY 1999 Congressional Budget Submittal, BPA, Fish and Wildlife Crosscut. (2) 1996-1997 Data - BPA White Paper, "What is BPA spending for fish and wildlife, March 1998. Available at http://www.efw.bpa.gov/Environment/EW/FISCAL/fiscal1.html

Notes: For FY85-FY 95: BPA Power Purchases for Fish Enhancement and "Foregone Revenues" from Source (1)
For FY96 and FY 97: iower purchases, foregone revenue and other river operations from Source (2). FY85- FY 95 Program FY 85-FY95: Program expenditures include "Direct Fish and Wildlife Program,, "Reimbursable," and "Program Related Fixed Expenses" from Source (1) and FY96-FY97 "Direct fish and wildlife program,", "Reimbursables," and Debt service on capital investment" from Source (2).

power production cannot be definitively separated from other factors that adversely affect these stocks. However, it is clear that more environmental costs associated with anadromous fish decline are being internalized in power rates. The graph below shows the increases in BPA's fish and wildlife expenditures over time as reported in BPA's FY 1999 budget submittal:[9]

Unfortunately, the growth in internalized cost of damage to fisheries does not mean that the external costs are necessarily declining (though external costs may be lower than they would have been without mitigation.) It is possible that both the internal and external costs of damage to fisheries from hydropower are increasing simultaneously. This is another way of saying that we are paying substantially more for fish recovery in power rates while the condition of the stocks continues to deteriorate. This situation appears to be unacceptable to power users and fish advocates alike.

2.3.4.2 Global climate change

In 1995, the International Panel on Climate Change, a collection of 2000 of the world's leading climate scientists, concluded that "scientific evidence suggests a discernable human influence on global climate."[10] The IPCC concluded that in all of the scenarios it examined the "average rate of warming would probably be greater than any seen in the last 10,000 years."[11] While recent temperature patterns may be due to a variety of causes in addition to long-term global climate change, the recent trend is clear: 1998 was the warmest year since the first temperature records were kept beginning in the 1880s, and the 10 hottest years on record have occurred since 1980. Research documenting temperatures and atmospheric chemistry over time confirms that warming trends coincide with periods of high concentrations of carbon dioxide. (See Figure 2.16.)

While substantial uncertainty remains regarding the timing, magnitude, and local impacts of global climate change, relatively little disagreement exists on the basic chemistry and trend. To the extent that uncertainty remains, it cuts both ways: scenarios under which global climate could change dramatically and abruptly appear to be as likely as scenarios in which change is gradual and less disruptive.

Global climate change is attributable to the increase in concentrations of various heat trapping gases in the atmosphere. These gases and their estimated relative contribution to global warming as a share of Washington's total contribution are depicted in the chart below. The chart also depicts the relative contributions of different activities to greenhouse gas emissions in Washington.

Transportation-related uses are the largest and fastest-growing source of greenhouse gas emissions from Washington sources. However, electricity production is a significant source of carbon dioxide. Most of the carbon dioxide produced by electric generators that serve Washington loads is produced by the Centralia and Colstrip coal-fired power plants.

The likely local impacts of climate changes are characterized in a 1997 report from the Joint Institute for the Study of Atmosphere and Oceans.[12] In the Pacific Northwest, the most dramatic effects are likely to come from reduced snowpack due to warmer winter temperatures. More precipitation is likely to fall as rain in the winter and spring, causing more flooding early in the year and drought later in the year. Reduced snowpack means changes in the timing and reductions in the amount of

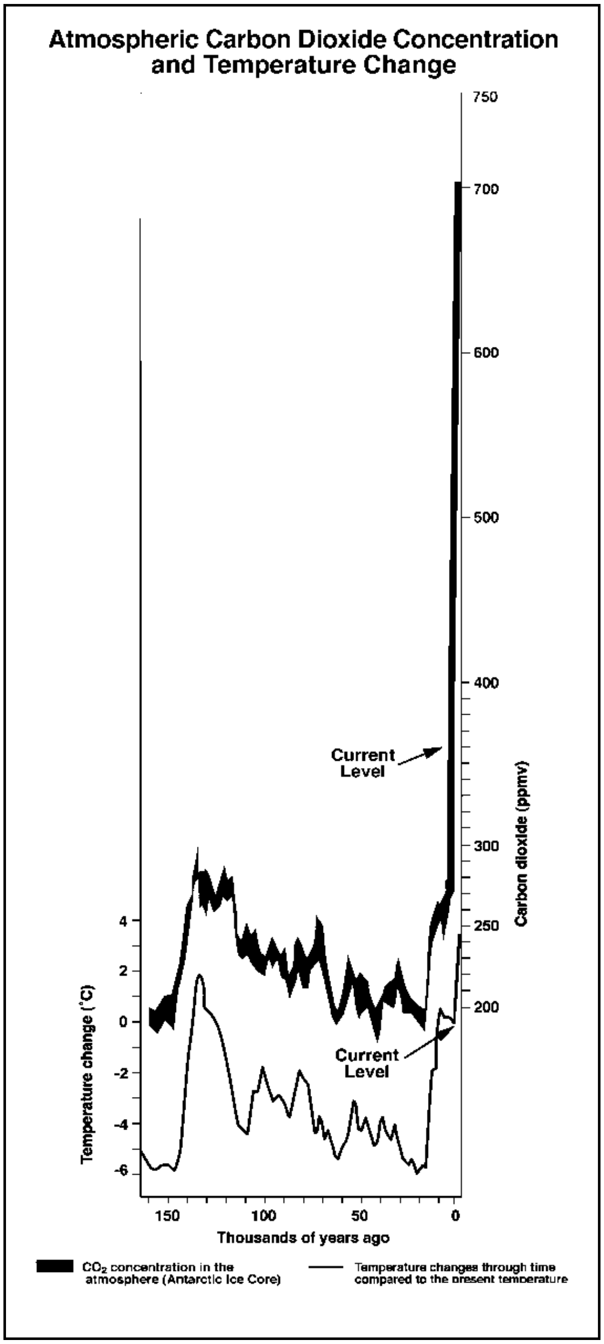
Significant impacts to forests, agriculture, coastal areas, and other ecosystems are also likely. While some impacts from climate change may appear to be beneficial, human systems are adapted to a relatively stable climate regime. Adaptations to rising sea levels, changed agricultural patterns, spread of tropical diseases, and volatile changes in weather are certain to be costly.

Virtually all of the costs of climate change are presently external to electric power prices. Unlike other pollutants, carbon dioxide is almost entirely unregulated, and few jurisdictions or utilities have incurred costs to mitigate it. Last year, Oregon began to internalize carbon dioxide costs when it incorporated carbon emission standards in its energy facility siting statute. Under the new law (HB 3283), electric generating facilities sited in Oregon must mitigate carbon emissions to a level 17% lower than the most carbon-efficient power plant operating in the U.S. at the time the new plant is permitted. This can be accomplished through emission reduction at the plant or payment of $0.57 per ton of carbon into a fund for carbon mitigation projects.

The 1997 Kyoto protocol, negotiated by more than 150 countries, would require the U.S. to reduce its greenhouse gas emissions to 7% below 1990 levels by period 2008-2012. Scientists indicate that substantially greater reductions (50-70%) would be necessary to stabilize the climate.[14]

Even though most of our power comes from hydroelectricity, internalization of carbon costs in power prices could have a significant effect on prices in Washington, depending on how it is accomplished. (Here again, internalization of costs in prices does not equate to total cost increases, since higher power prices may be offset by lower external environmental costs.) The Table 2.5 below shows the effects on prices of power from coal and gas-fired resources under different levels of

Figure 2.16

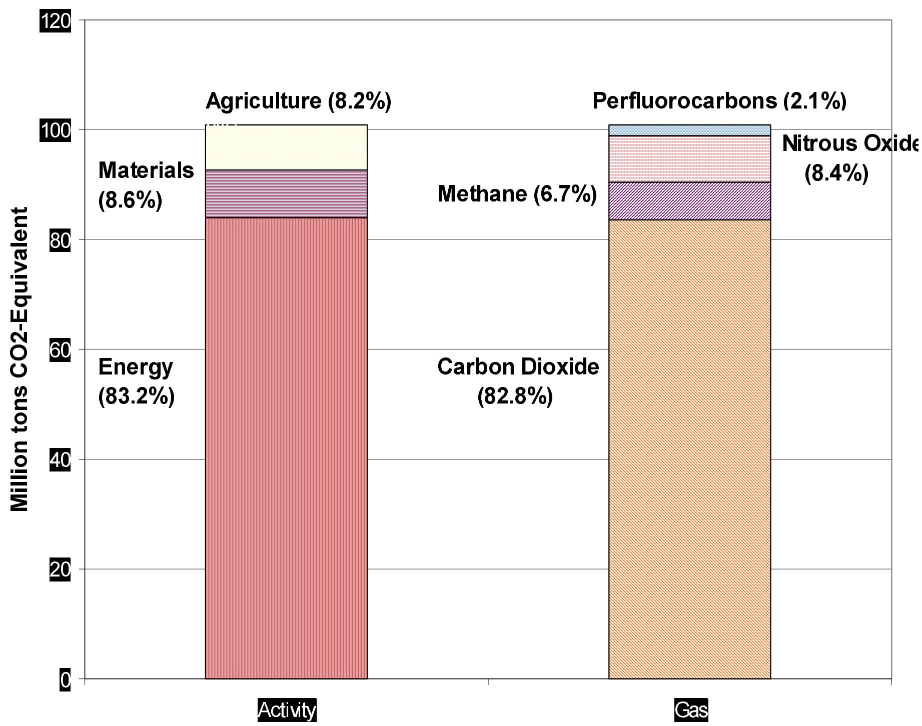


on how it is accomplished. (Here again, internalization of costs in prices does not equate to total cost increases, since higher power prices may be offset by lower external environmental costs.) The Table 2.5 below shows the effects on prices of power from coal and gas-fired resources under different levels of carbon taxation. Not all of these price increases would be passed on in power prices because internalization of carbon costs would probably induce fuel switching away from carbon intensive fuels. (As a reference point, the Council of Economic Advisors estimates that the Kyoto target can be reached at a cost of $14/ton to $23/ton.[15])

Table 2.5 Electricity Costs of Carbon Taxes[16]

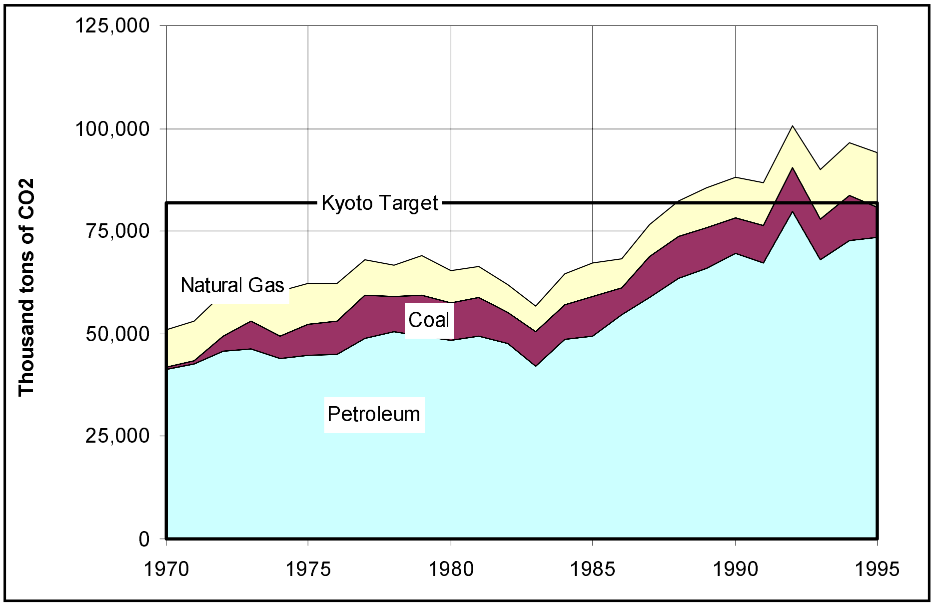
	$10/ton	$25/ton	$50/ton
	Cents/kWh	Cents/kWh	Cents/kWh
Resource			
Coal (PNW)	0.9	2.3	4.6
Natural Gas (CC)	0.5	1.2	2.4

Figure 2.17 Washington Greenhouse Gas Emissions



If and when the costs of carbon dioxide emissions are internalized, Washington's hydroelectric resources would become even more economically valuable*. How this value would be manifested and distributed depends on how carbon reduction strategies are implemented. Internalization of carbon costs would also increase the economic advantages associated with energy efficiency measures that deliver more

Figure 2.18 Carbon Dioxide Emissions from Energy Use by Source



energy services from increasingly valuable hydropower supplies. Internalization of carbon costs also improves the economics of other renewable energy sources, and could lead to a transition toward low-carbon or carbon-free energy sources.

2.3.4.3 Increasing competition in electric power markets

Growing competition in electric power markets can affect both the total environmental cost of electric service and the distribution of environmental costs between internal costs (included in power rates) and external costs (not included in power rates). Some of these potential effects are described below.

- *Insofar as competition focuses on minimizing electric power prices, it may increase pressure to increase external costs.* Since prices include only internalized environmental costs, price competition may tend to generate pressure to externalize environmental costs, or at least to avoid internalizing them. For instance, fossil-fueled generators in a regulated monopoly environment can pass on the cost of required emissions controls to consumers through regulated prices. In a competitive environment, requirements for additional pollution controls may render these generators uncompetitive. To the extent that competitive pressure prevents internalization of environmental costs, it tends to raise external costs, skew price signals, and thereby decrease economic efficiency.
- *Some forms of competition may tend to undermine utility investment in cost-effective energy efficiency and renewable resources.* Competitive pressure appears to be reducing investment in and accomplishment of cost-effective energy efficiency and renewable resources. (See section 9). Although these resources may minimize total costs, they may not

* However, the effects of climate change on hydrology could significantly reduce hydropower production. This is particularly true in the Columbia Basin, where reduced snowpack means substantially reduced storage capacity for hydroelectric production

minimize rates, for two reasons. First, energy efficiency reduces consumption and thereby reduces the number of kilowatt-hours sold over which utilities spread their costs. Therefore, even when energy efficiency is the cheapest way to provide energy service, it may put upward pressure on rates. Second, both energy efficiency and renewable resources tend to have lower external costs than conventional power sources. Since many of these costs are not included in rates, the environmental advantages of these resources do not improve their ability to compete on price. Investment in these resources is not necessarily inconsistent with retail power competition. Indeed, in most states that have restructured, the cost of these investments is passed on through a non-bypassable distribution charge, where it imposes no competitive handicap on any supplier. Only where the cost of these investments is bundled with generation costs does power supply competition tend to undermine them.

- *Competition may increase the availability of "green power" sources for consumers willing to pay a premium for environmental quality.* Green power marketing has already begun in many places, including Washington. Green marketing may allow consumers' expressed preference for environmentally superior resources to be translated into a market proposition, and thereby decrease environmental costs. Some green power marketing uses the premium revenues for new investment in environmentally superior resources. This would tend to reduce environmental costs. Other green marketing programs redistribute the cost of existing resources to those consumers who express a willingness to pay more for them. This would not reduce environmental costs. Markets for green resources may tend to exhibit a market failure that economists attribute to the "public goods" problem: The environmental advantages of "green" resources are shared by everyone, regardless of whether they choose to pay more for those resources or not. And by the same token, those who choose to pay more for "green" power must still bear the environmental costs of conventional resources. Therefore, green power markets are likely to exhibit the same market failure as other public goods: chronic underinvestment.[17] This public goods problem provides the economic rationale for collective investments in military protection, lighthouses, and other goods, which cannot be secured in sufficient quantities through private investment alone.

2.3.5 Technology

Electric technology trends are discussed briefly below. While electricity technology has not been a major focus of legislative debate, it is a subject that may be worthy of somewhat more detailed analysis than the agencies have undertaken within the scope and time constraints of this study[*].

Technological innovations in both electricity-generating equipment and energy-using equipment have significantly reduced the cost of electricity over time. The NWPPC's 1996 Draft Plan aptly illustrates the significance of this technological change in the recent past. In 1991, the new marginal generating resource was assumed to be a gasified coal facility. In 1996, the marginal resource is a gas-fired turbine. The gas turbine has a 73% lower capital cost, 30% greater thermal efficiency, and 15 % greater availability and, consequently a 50% lower levelized production cost than the gasified coal unit.[18] In addition, the levels of SO2, NOx, and CO2 emissions are 50% to 85% lower.

Ongoing technological changes are likely to include increases in the efficiency of generation, smaller and more distributed generating technologies, decreased production of criteria air pollutants, and growing interaction with information, communications and transportation technologies. These changes seem likely to decrease both internal and external costs of electric generation over time. New technologies are also likely to influence other costs of electricity operations through changes in metering and billing, load control, and greater utilization of infrastructure (e.g. cable or internet additions to power communications networks).

However, there are some indications that short-term competitive pressures may be squeezing out investments in research and development of energy technologies.

One recent study finds that, “research and development funding by 80 of North America’s largest investor-owned utilities fell by one-third between 1993 and 1996.”[19] On average, industrial firms in the U.S. spend approximately 3.1% of sales on R&D. In 1994, US utilities, on average, devoted .3% of sales to R&D, and substantial reductions have occurred since then.[20] To respond to this situation, at least seven states with restructuring initiatives have included R&D among the categories of investment that are supported by a system benefits charge.

2.3.5.1 Natural Gas Combustion Turbines

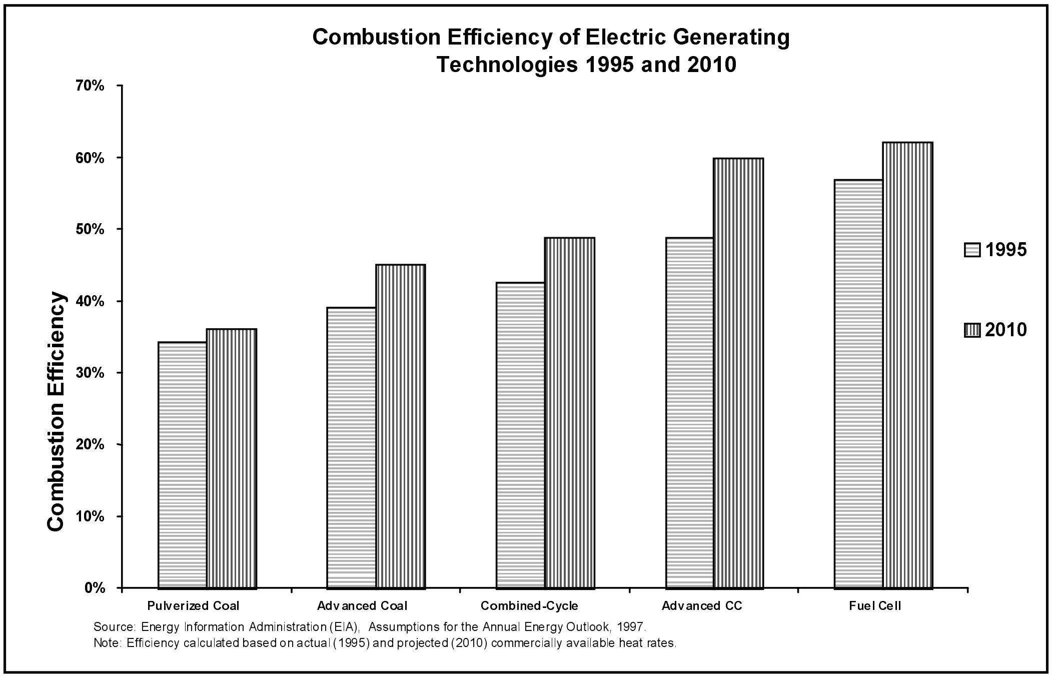
The natural gas combined cycle combustion turbine is likely to remain the most common new generating technology for the immediately foreseeable future. The Energy Information Administration (EIA), in its 1998 Energy Outlook, estimates that 85% of new electricity generation from 1996 to 2020 will be combined-cycle or combustion turbine technology fueled by natural gas.[21]

Continuing advances in high temperature materials coupled with improved turbine design and control technologies will continue to push up the thermal efficiency of this equipment. The NWPPC uses a 0.5% per year increase in thermal efficiency for its resource projections. EIA reaches similar conclusions. Figure 2.19 illustrates EIA’s projections for efficiency improvements for combustion turbines along with other comparable generating technologies. By 2010, the thermal efficiency of advanced combine cycle facilities is expected to increase from 49 % to 60%.

In addition to improved efficiency, the capital costs of new generating technologies are also likely to decline. EIA estimates that the capital cost components of advanced combine cycle units will decline from 7.5 mills/kWh ($1996) in 2005 to 7.2 mills/kWh ($1996) by 2020.[22] Capital costs represent about one-quarter of the total estimated cost of advanced combined cycle combustion turbines, so marginal reductions in capital cost will probably not be as important as fuel price trends in determining overall costs.

* More detailed information on electric technology trends is available at the Electric mower o esearch Institute’s Electricity Technology o oadmap at http:LLwww.epri.comL and the U.S. a epartment of Energy’s o enewable and Energy Efficiency Network (Eo EN) at http:LL www.eren.doe.govL

Figure 2.19



2.3.5.2 Distributed Technologies

Smaller scale distributed generation may assume a larger share of future electricity generation. Much research is underway on distributed technologies such as fuel cells, microturbines, photovoltaics, and advanced energy storage devices.[23] Advances in fuel cell technology are being driven rapidly by a number of factors, including the growing demand for clean transportation alternatives. Microturbines are likely to be sized at 25-75 kW, fuel cells from a few kW to a megawatt or more, and PV rooftop systems may be as small as a few kW each. Most of these technologies can be applied either as an additional component of the existing electricity grid or as stand alone, grid-independent systems. Estimates of the potential penetration of such technologies into the market range from as much as 20% of the new generation capacity additions over the next 10 to 12 years to only negligible contributions during that period.[24]

- **Microturbines:** Mass produced microturbines in sizes below 100 kW are now beginning to enter the market. These small units, when powered by natural gas, can generate electricity at four to five cents per kWh.[25] Some of the likely applications include placement at the end of transmission and distribution lines to avoid high cost upgrades, installation as uninterruptible power supply units, and use as a dedicated prime mover for pumps, air conditioning, or process equipment. Many of the large manufacturers of conventional turbines and generators are developing microturbine product lines.
- **Fuel Cells:** Fuel cell technology is based on an electrochemical (rather than thermal) reaction between hydrogen and oxygen that produces direct current electricity and heat. The residual product from fuel cells in pure water. A wide range of feedstocks (including natural gas, coal, biomass)

can subjected to a reforming process to extract hydrogen fuel for the cells. Successful development and production of fuel cells on a large scale could have major impacts on the costs and market structure of electricity production. Although currently too costly for most applications at 15 cents/ kWh or more, they hold major promise for numerous future applications. Substantial research is underway on a wide range of fuel cell technologies including phosphoric acid, molten carbonate, alkaline, solid oxide, and proton exchange membranes.[26] Fuel cells are highly modular and can be manufactured in sizes from a few kW to several megawatts. Given the substantial investments in fuel cell research it is reasonable to assume that manufacturing cost and production costs will continue to decline.

- **Storage Devices:** Electric, chemical, and mechanical storage devices can serve as storage media in applications ranging from individual homes to utility systems. For utilities, new storage technologies can help increase utilization of transmission and distribution equipment, decrease reserve margins, allow for better integration of intermittent sources (such as wind and photovoltaics) into utility systems, and increase system reliability.[27] For electricity users, storage systems can increase power quality, provide uninterruptible power supply, provide storage and backup for intermittent renewable technologies, and reduce peak demand. Substantial research and development is under way to improve battery and flywheel technology. R&D is especially active in the area of low-cost, high power density batteries for transportation applications.[28] Flywheels offer the ability to store large amounts of energy at a high energy density. Improvements in materials, magnetic bearings, and vacuum chambers have reduced storage losses. Development of flywheels for utilities has been focused on power quality applications.[29]

2.3.5.3 Hydroelectric generation

Hydroelectric generation is unlikely to increase in the U.S. overall and in the Pacific Northwest in particular. However, there is currently research and development underway to improve the technology of hydroelectric turbines so that they are more 'fish friendly' and can also operate more effectively under a wider range of mandated water flow conditions. EPRI estimates that it will require 2 to 10 years for prototype develop-

Table 2.6 Distributed Generation Options

Technology	Size	Efficiency (%)	Cost Range
♦ Microturbines	25-100 kW	26-30	4 –5 cents/kWh
♦ Fuel Cells (numerous technologies)	200 watts – 5 MW	40 –65	$3000/kW
♦ Photovoltaic	<1 – 1000 kW	10-20	17-25 cents/kWh
Storage Devices			
♦ Battery Storage	500- 5000 kWh	70 –75	$400 - $1000/kW
♦ Flywheels	2-20 kWh	70 –80	$3000 - $6000/kW

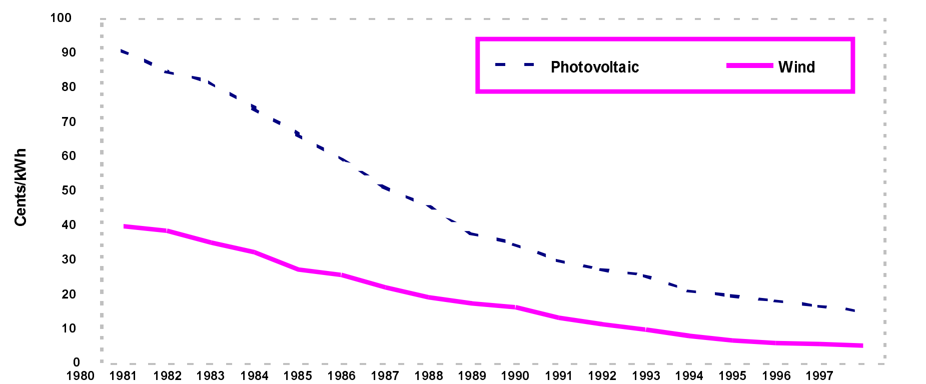
Sources: EPRI Journal, March/April 1998. Cost range for U.S. DOE, Renewable Energy Technology Characterizations, "Overview of Energy Storage Technologies," 1997.

ment and testing of such improved turbines and development of variable speed, variable power turbines and controls.[30]

2.3.5.4 Renewable Technologies

Renewable energy technologies in addition to hydropower include wind, solar thermal, solar photovoltaic, geothermal, landfill gas and biomass. Currently the internal costs of these technologies are moderately to substantially higher than natural gas combustion turbines. Their external costs, however, are generally considered to be lower. The NWPPC's 1996 cost estimates range from 4.1 cents/kWh for wind to 17.8 cents/kWh for photovoltaic generation.[31] However, the costs of these technologies have declined significantly over the last two decades. Figure 2.20 illustrates this decline. Because some of these technologies lend themselves to distributed application, they are cost-effective in some remote applications now. For example, solar photovoltaics are a cost-effective option for pumping water for livestock in many areas.

Figure 2.20 Decreasing Costs of Renewable Energy Sources



Source: U.S. DOE, *Technology Opportunities to Reduce U.S. GreenhouseGas Emissions*, p. 2-37, 1997.

2.3.5.5 Cogeneration

Cogeneration or combined heat and power (CHP) is the simultaneous production of electricity and heat. Cogeneration allows for increased thermal efficiency through productive use of what would otherwise be waste heat from combustion. Cogeneration/CHP dates back to the early years of the electricity industry when small, localized power plants, predominately at industrial sites, produced both electricity and heat for industrial processes. As the size of generating plants expanded and large plants were often sited outside major population centers, cogeneration's share of electricity production waned. However, interest in cogeneration, both domestically and internationally, is again increasing. One factor driving this increase is the availability of small and clean distributed generation, which allows electric generators to be closer to heat-demanding processes or commercial loads. Overall, efficiencies of 70 to 80 percent make cogeneration very attractive to both independent power producers and end users.[32] Because of the high thermal efficiencies it allows, cogeneration may contribute significantly to the achievement of carbon emission reduction goals.

Washington currently has more than 300 MW of installed cogeneration capacity.

2.3.5.6 Energy-using equipment

Just as improvements in electric generating technology have steadily increased the conversion efficiency of electricity production, technological improvements in electric using equipment have dramatically increased end use efficiency. Over the last 25 years, the development and adoption of building energy codes, implementation of large scale utility conservation programs, national appliance and equipment efficiency standards, and state conservation efforts have driven technological innovation. High efficiency motors, windows, electronic ballasts, and highly sophisticated energy management systems are a few of the many new electricity-saving devices. These technologies have reduced the cost of electric service by displacing the need for more costly new supplies and lowering operating costs for residential, commercial, and industrial equipment.

The NWPPC estimates that “the cumulative savings enjoyed by the region’s electricity consumers in 1996 amounts to about 1,000 average megawatts.” [*] The Council estimates that the region still has approximately 1,535 average megawatts of cost-effective conservation potential available at an average levelized cost of 1.7 cents/kWh.[**] Much of this potential involves increased commercialization of energy saving technology.

Figure 2.21 shows the decline in the electricity intensity of Washington’s economy in real dollar terms. Technological improvement is one of the important factors contributing to this decline.

2.3.5.7 Communications and information technology

Communications and information technologies present substantial opportunities to reduce electric service costs and expand product and service diversity. These technologies allow for remote meter reading, real-time pricing, direct load management, and remote monitoring of energy efficiency or power quality.[33] Remote meter reading is likely to be the most significant near-term application, allowing utilities to decrease their operating costs while linking them more closely to their customer base. Such enhanced links also open up the opportunity for energy service providers to form new partnerships and to provide new services.

2.3.6 Fuel

Washington’s primary reliance on hydroelectric power has tended to insulate it to some degree from trends in the price of fossil fuels. However, a significant portion of the power consumed by Washington citizens comes from large, coal-fired power plants that were built in the 1970s. Moreover, almost all new generating capacity that has been installed in the 1990s has been fired with natural gas, and gas appears to be the resource of choice for the foreseeable future. Fuel prices are likely to play a

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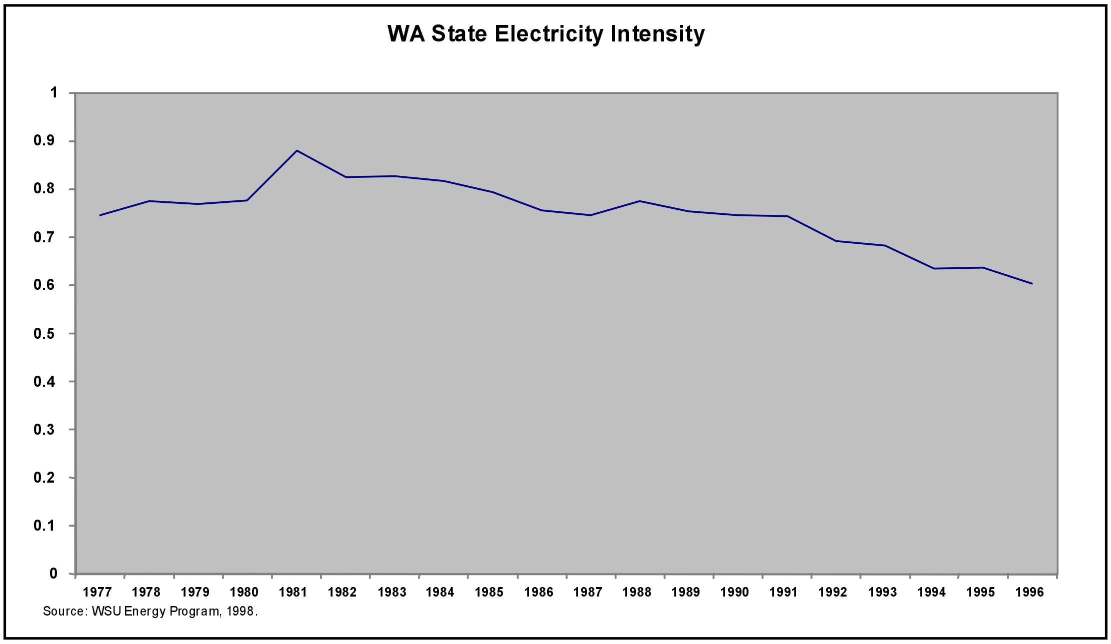
* NWmmC, courth araft mlan, mage 4-9. See also the public purposes section of this report for more discussion of conservation achievements.

** mage 6-5.

Figure 2.21



growing role in determining the price Washington consumers pay for electricity.

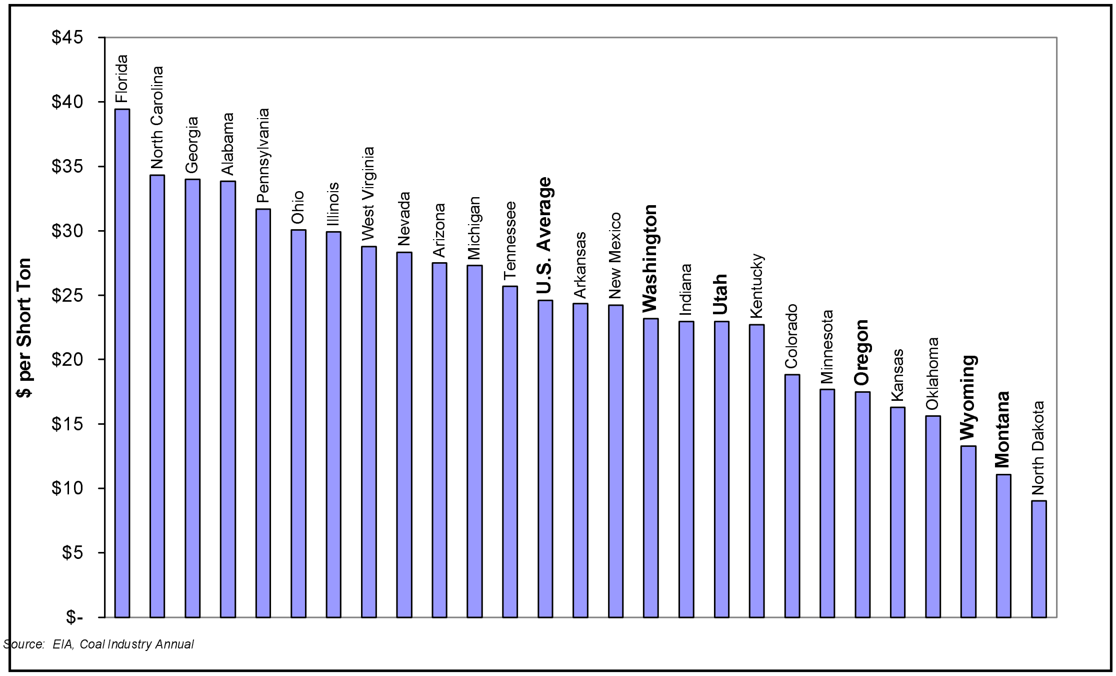
Fuel prices in the Northwest tend to be lower than in the rest of the country. Figure 2.22 compares coal prices at electric utilities in selected states around the country. The boldface type indicates states in which coal plants owned by utilities serving Washington customers are located. Wyoming and Montana, where the bulk of the Northwest's coal-fired generating capacity is located, enjoy some of the lowest coal prices in the country. This is due both to the characteristics of the resource (the coal tends to lie close to the surface and be low in sulfur) and to the location of the generating plants at the minemouth, reducing the cost of transporting the fuel. Centralia coal is cheaper than the national average.

Figure 2.23 compares city gate natural gas prices in selected states and Census Divisions. Washington, Oregon and Idaho enjoy some of the lowest natural gas prices in the country, even lower than in gas-producing regions like the West South Central (which includes Oklahoma, Texas and Louisiana). This is due primarily to the availability of cheap Canadian supplies, and secondarily to inexpensive production in Wyoming and northwestern Colorado.

There is some question about whether this cost advantage will continue, as the basis differentials were larger in 1996 and 1997 than they have been historically. Also, several projects are in the works, which would increase pipeline capacity from the Rocky Mountain region eastward, both in the U.S. and in Canada. Still, the higher cost of shipping gas eastward suggests that the Northwest may enjoy relatively low-cost gas supplies for the foreseeable future.

The next two charts examine the trend of fuel prices over time, both in real and in nominal terms. Prices for coal and natural gas have exhibited similar trends over the past thirty years or so. Both were cheap in real terms in the early 1970s, and both saw steep price increases throughout the 1970s as demand outpaced supply.

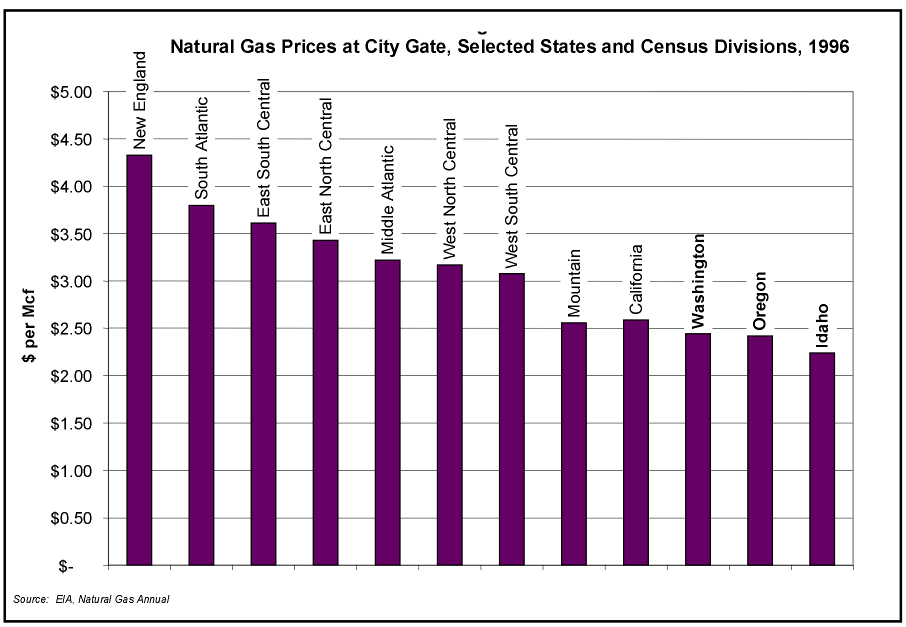
Figure 2.22 **Coal Prices to Electric Utilities, Selected States, 1997**



Coal prices across the country have declined steadily since, peaking at around $35 per ton in 1982-1984. The average price in 1997 was $26.16 per ton. In real terms, prices for coal delivered to electric utilities are less than half what they were fifteen years ago.

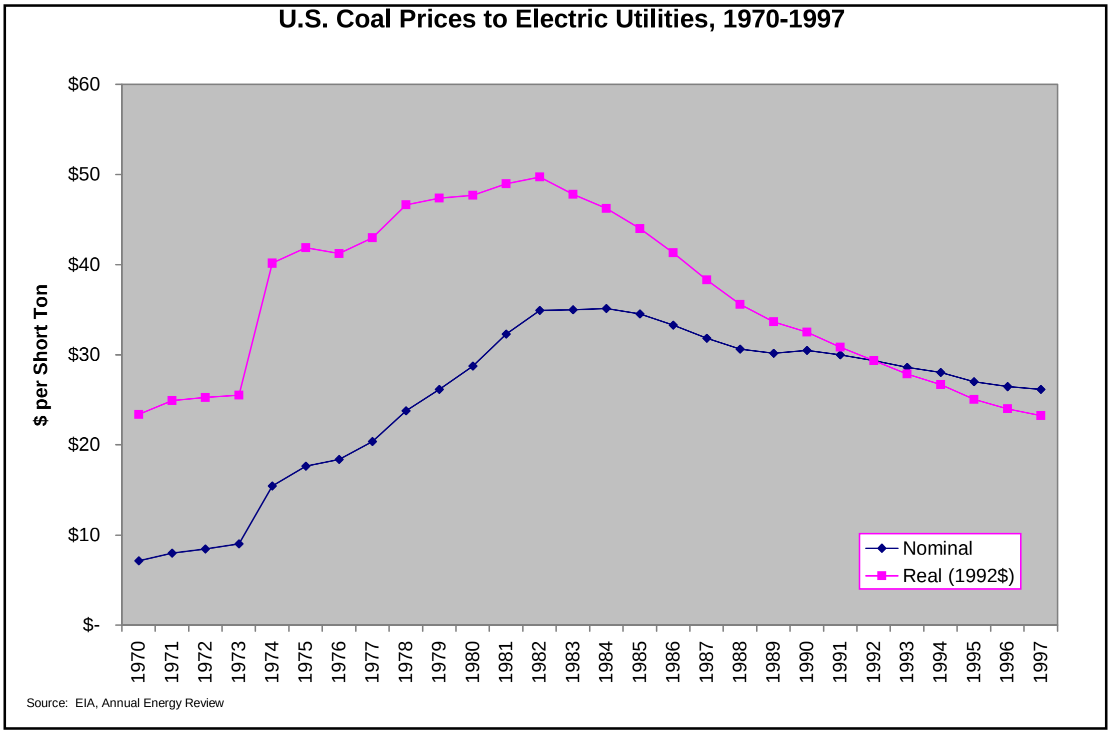
The story is similar, though more pronounced, for natural gas. Gas prices skyrocketed in the 1970s, increasing over 500% in real terms between 1970 and 1983. Production increases and infrastructure improvements led to much lower prices by the

Figure 2.23



Note: *City gate prices were chosen as the most comparable indicator of natural gas commodity costs.*

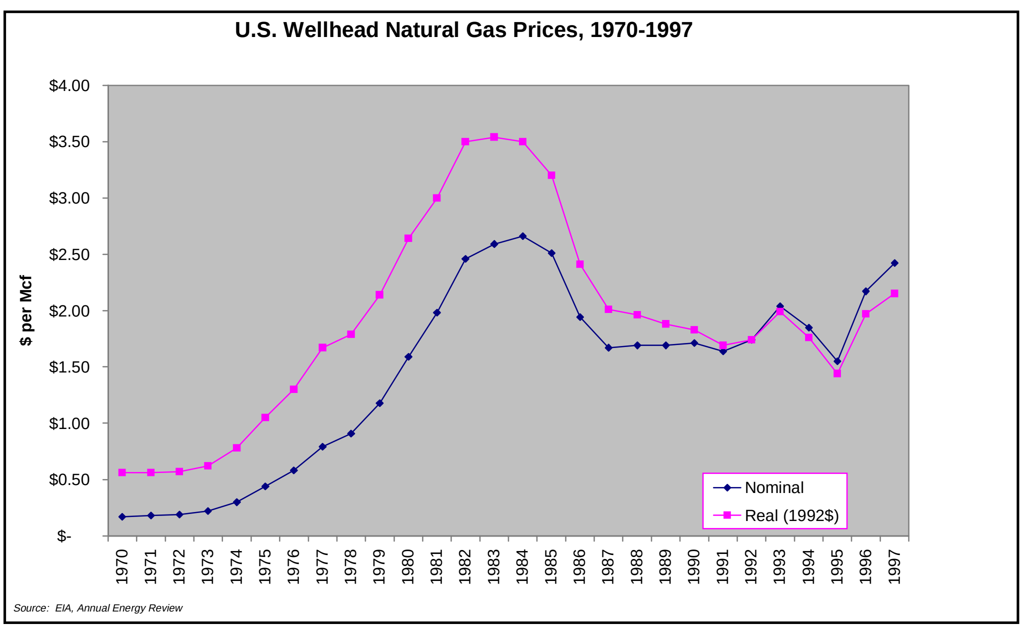
Figure 2.24



increases and infrastructure improvements led to much lower prices by the late 1980s, and prices fell to less than half their former levels in the mid-90s. The last three years have seen gas prices drifting back upwards. It remains to be seen whether this becomes a long-term trend.

Both natural gas and coal are fossil fuels with substantial environmental impacts, primarily in the form of air emissions. The costs of these impacts are not fully internalized. Burning coal produces harmful air pollutants including oxides of nitrogen (NO

Figure 2.25



produces no particulates or heavy metals, but does produce NO_X and CO. Both fuels produce carbon dioxide, the most prevalent greenhouse gas. In general, and particularly in the case of carbon dioxide, coal-fired generators produce substantially greater emissions per unit of energy than do gas-fired units.

While some of these environmental costs have been internalized through fuel-switching or the installation of pollution control equipment, increasing environmental liabilities are a factor that is likely to affect future fuel prices. For example, the coal industry is still in the process of complying with Phase I of the Clean Air Act Amendments of 1990, which require a 60% reduction in industry-wide SO_2 emissions by 2010. The Energy Information Administration has estimated that the cost to utilities of complying with Phase I of the 1990 CAAA has amounted to $836 million per year, in 1995 dollars.[34] Compliance with Phase II, which begins in 2000, is expected to be more costly. Minemouth coal may continue to get cheaper, but burning it will probably continue to get more expensive.

This is especially likely if the U.S. is to achieve the reductions in greenhouse gas emissions it pledged while negotiating the Kyoto protocol. The electric utility sector accounts for approximately one third of U.S. greenhouse gas emissions, and may be called upon to achieve a substantial portion of the U.S. target for emission reduction. This will require shifting generating capacity away from coal and towards lower carbon alternatives such as natural gas and renewables. Some internalization of carbon costs will probably be required in order to achieve these, or any, carbon reduction targets. This internalization will increase the price of electricity in proportion to the carbon emitted by the generation source, with the greatest increases falling on coal-fired power. (See Figures 2.24 for effects of various levels of carbon tax on price of power from coal and gas).

Carbon emission reduction efforts will probably also affect natural gas prices. Electric utilities may substantially increase their use of natural gas in an effort to reduce emissions from coal plants. This would put pressure on gas supply and cause prices to increase. Natural gas also contains carbon and would presumably be subject to any policy that internalizes carbon costs.

Endnotes for Section 2

[1] See, for example, Senate Bill 2499 in the 105th Congress.
[2] "Retail Wheeling and Restructuring Report," Edison Electric Institute, June 1997.
[3] National Regulatory Research Institute "Electric Industry Restructuring Box Score"; http://www.nrri.ohio-state.edu
[4] The average price of electricity in the 17 states that had mandated retail competition as of May 1998 was 8.6 cents/kWh, compared to an average price of 6 cents/kWh in the other states. ("Creating Competitive Markets in Electric Energy: A Critical Analysis of H.R.655" *Electricity Journal,* May 1998)
[5] "Comprehensive Review of the Northwest Energy System Final Report: Toward a Competitive Electric Power Industry for the 21st Century," December 12, 1996.
[6] However, BPA proposes in future power supply decisions to consider the extent to which DSI customers continued to purchase from BPA when contracts were renegotiated in 1995.
[7] *Fourth Northwest Conservation and Electric Power Plan*, Northwest Power Planning Council, 1998
[89] *1997 Pacific Northwest Loads and Resources Study,* the Bonneville Power Administration, December 1997.
[10] The agencies did not collect comparable data on internalization of fish costs from other hydropower operators, but anecdotal evidence suggests significant increases in recent years for many hydropower facilities.
[11] *[IPCC Second Assessment, Climate Change 1995. – full citation]*
[12] " IPCC Summary for Policymakers: The Science of Climate Change", page 25
[13] Snover, Amy, Edward Miles, and Blair Henry, OSTP/USGCRP Regional Workshop on the Impacts of Global Climate Change on the Pacific Northwest, NOAA Climate and Global Change Special Report No. 11, March 1998.
[14] See, for example, "Thermal Limits and Ocean Migration of Sockeye Salmon: long-term Consequences of Global Warming," *Canadian Journal of Fisheries and Aquatic Science*, Volume 55, 1998, D.W. Welch, Y. Ishida, and K. Nagasawa.
[15] IPCC, p.[xx]
[16] Testimony of Dr. Janet Yellen, House Commerce Subcommittee on Energy and Power, March 4, 1998.
[17] Northwest Power Planning Council, *Draft Fourth Northwest Power Plan,* Table 6-3
[18] See Hardin, Garrett, "The Tragedy of the Commons," *Science*, 162 1968. pp. 1243-1248
[19] Northwest Power Planning Council, *Draft Fourth Northwest Power Plan,* Table 2-1, page 2-8
[20] "Changes in Electricity-Related R&D Funding," US General Accounting Office, August 1996 GAO/RCED-96-203
[21] "US National Investment in Energy R&D: 1974-1996", JJ Dooley, PNNL-11788, December 1997
[22] Energy Information Administration, *Annual Energy Outlook 1998 with Projections Through 2020,* DOE/EIA-0380(98), December 1997, page 51.
[23] EIA, *Outlook 1998,* page 52.
[24] EPRI Journal, "Emerging Markets for Distributed Resources," March/April 1998
[25] EPRI Journal, "Emerging Markets…"
[26] "Good-bye Bulk Power," Public Power, March-April 1998, page 21.
[27] See for example, Avista Labs of Spokane at http://www.avistalabs.com/home/index.html for information on fuel cell research.
[28] U.S. DOE, Renewable Energy Technology Characterizations, "Overview of Energy Storage Technologies," 1997 at http://www.eren.doe.gov/utilities/techchar.html.
[29] See for example, "Study Progress: Electric-Car Batteries Are on Track," Electric Power Research Institute, 1998.
[30] "Energy Storage Technologies," Appendix A, U.S. DOE, Renewable Energy Technology Characterizations, 1997.

[31] Electric Power Research Institute, *Powering Progress, The Electricity Technology Roadmap Initiative. Background Report: A Preliminary Vision of Opportunities,* August 1997, page 2-16.
[32] NWPPC, *1996 Plan,* Table 6-1, page 6-5.
[33] Tim Hennagir, "CHP's Promise," Independent Energy, January/February, 1998.
[34] Michael Kintner-Meyer, "Communication Technologies for Energy Management and Energy Services" ACEEE Summer Study, 1998, page 8.204
[35] EIA, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, April, 1997, available on the EIA website: http://www.eia.doe.gov/cneaf/electricity/clean_air_upd97/exec_sum.html